**DRAFT: SUBJECT TO PANEL COMPLETION, REVIEW AND EDITING**

# A REVIEW OF CAPTURE CAPTURE AND STORAGE IN CALIFORNIA

A Report to the California Energy Commission, the California Public Utility Commission, and the California Air Resources Board.

2010

## I. Executive Summary (5-6 pages)

## II. Overview of the Review Panel Process

### II.1. Introduction

Carbon capture and storage (CCS) is a technology which captures carbon dioxide (CO2) and stores or sequesters the gas in sub-surface geologic reservoirs. Called geologic carbon sequestration, this technology prevents the buildup of CO2 in the atmosphere. CO2 can also be stored in forests, rangelands, agricultural lands and wetland through terrestrial carbon sequestration through natural uptake of CO2.

CCS has been recognized as necessary for meeting California's energy and climate change goals. Since California's electricity sector is dominated by natural gas and relies on imported coal for 20 percent of its electricity needs, CCS presents a means for retrofitting existing industrial facilities, such as power plants, cement plants and oil refineries, in order to lower their carbon dioxide emissions. Because CCS has national and international significance, states like California should demonstrate leadership in stimulating the introduction of this rapidly emerging technology.

### II.2. Role of the Carbon Capture and Storage Review Panel

Recognizing the importance of CCS for California's industrial sector, the California Public Utilities Commission, Energy Commission, Air Resources Board, and the Department of Conservation created a CCS Review Panel, composed of industry, academic and technical experts, and consumer interests. A complete list of the Panel members and their qualifications is provided in the Appendix to this Report.

This Panel was asked to identify and seek to resolve the legal and regulatory ambiguities surrounding CCS technology, particularly for geologic CCS projects. Specifically, this Panel was formed to address a number of key questions affecting this rapidly emerging industry.

1. Who owns the reservoir and the injected CO2?
2. Who is the one responsible for the legal liability if CO2 escapes?

3. What happens to the injected $CO_2$ over time? Does it leak?
4. Will the public accept it? Can the impacts be mitigated?
5. What is the appropriate state regulatory and policy framework?
6. How can the permitting of first-of-its kind CCS projects be streamlined?

## II.3. Need for Clear, State Policy and Regulatory Framework

A statutory or regulatory framework for geologic carbon sequestration must be clear, transparent, flexible, and adaptable. In addition, the State of California should establish a clear state policy, which recognizes carbon dioxide as a valuable and marketable commodity which can be used for multiple benefits, including injection of $CO_2$ for use in enhancing oil or natural gas recovery, use of $CO_2$ to produce chemical products, such as industrial fertilizers or solvents, producing biofuels from algae, and retrofitting coal power plants to reduce their carbon footprint.

Gaps currently exist in how California regulations will apply to geologic CCS projects, especially those projects which do not involve Enhanced Oil Recovery (EOR). Some of these gaps may be addressed by the U. S. Environmental Protection Agency in its proposed rulemaking or by an application by a California state agency for delegated authority ("primacy") from US EPA. Also, no state agency has the explicit authority to regulate $CO_2$ pipelines, and monitoring, measurement and verification (MMV) requirements have yet to be established.

California companies are investing in CCS technology as a means for reducing greenhouse gas (GHG) emissions while maintaining their economic viability in a changing regulatory and economic climate.

Because the CCS industry is still advancing, the economics of the first-of-its-kind demonstration projects are not as favorable as conventional technologies. As a result, many have relied on federal funding from the U. S. Department of Energy (DOE), to underwrite the financial risk.

There is a need for a clearly articulated state policy which recognizes the benefits of CCS technology as both a market commodity and a GHG reduction strategy.

Companies recognize the importance of CCS as a growing market, similar to renewable electricity, which can produce equivalent carbon reductions. State policy should recognize the value of low-carbon electricity using CCS technology, just as it has recognized the value of renewable energy resources to California's electricity system.

In 2006, the California Legislature enacted Assembly Bill 1925 (Blakeslee, Chapter 471, Statures of 2006). This law directed the California Energy Commission to assess the State's readiness for CCS technologies, particular geologic sequestration. A 2007 Report by the Energy Commission identified a number of technical and regulatory issues some of which the CCS Review Panel is addressing:

1. What role should the U. S. Environmental Protection Agency play in regulating CCS, given its current role in regulation underground storage and injection?

2. What role should the state play in regulating geological carbon sequestration?

3. Which state regulatory agency is the most logical and the best equipped to serve as the lead agency for CCS development projects? Should the state oil and gas regulatory agency be the

lead agency for regulating CCS projects? Or should an environmental or energy agency be designated?

4. How should property rights issues relating to sub-surface pore space be determined?

5. How should the State of California address long-term monitoring and insurance liability following formal closure of the injection well?

6. Should an industry-funded and state-administered liability trust fund be established?

7. Or alternatively, should legal liability and risk mitigation be within the purview of the federal government?

8. How can California learn from past experience with Enhanced Oil Recovery operations in crafting its own laws and regulations affecting CCS project development?

The CCS Review Panel will be providing specific recommendations, including new state legislation, state and federal policy support, and identifying mechanisms to clarify regulatory roles and responsibilities of the key permitting agencies.

### II.4. Public Meetings and Stakeholder Input

The Panel has held four public meetings on April 22, June 2, August 18 and October 21, 2010, designed to solicit input from technical experts and key stakeholders and to allow deliberation among the Panel members in an open, public setting. Public testimony and written comments were filed and can be found in the Appendix to this Report.

In addition, a Technical Advisory Team of state agency representatives and expert consultants was formed to assist the Panel in its deliberations. A series of technical presentations and staff white papers on key topics which are listed in the Appendix.

### II.5. California Policy Context for CCS

The major policy driver for CCS technology was the enactment of the Global Warming Solutions Act of 2006 (Assembly Bill 32, Chapter 488, Statutes of 2006). This landmark legislation declares global warming as a serious threat to California's environment and economy. The law requires a reduction in statewide GHG emissions to 1990 levels by the year 2020 and to 2000 levels by 2050.

The California Air Resources Board (ARB) is the agency responsible for developing a comprehensive, multi-year program to reduce GHG emissions in California. Under its authority from AB 32, the ARB is establishing regulations, programs and reporting requirements, including:

- The Low-Carbon Fuel Standard requiring a 10 percent reduction in the carbon intensity of liquid transportation fuels by 2020
- Mandatory reporting requirements for major GHG emitters
- Specific GHG reducing measures

- A cap-and-trade program which allows the trading of emission allowances or offset credits among participants in the emerging carbon market.

The Climate Change Scoping Plan, which the ARB adopted in December 2008, recognizes the important role of CCS as a long-term (post-2020) strategy. CCS is specified by ARB as an option for lowering the carbon intensity of high carbon intensity crude oil. However, the Scoping Plan does not measure the potential GHG reductions from this technology nor does it provide a reporting mechanism for measuring CO2 emission reductions from CCS technology.

It is not yet clear whether or how CCS developers will be given credit for carbon reductions either under the ARB's mandatory reporting rules or under a proposed cap-and-trade program. One option is for ARB to allow CCS-related reductions as offsets or allowances that can be sold in the market to major GHG emitters. Another option would be for ARB to adopt GHG reporting protocols for CCS projects that could be used to measure and verify CO2 reductions. In any case, a methodology for quantifying the effects of CCS technology would need to be developed.

### II.6. GHG Performance Standards for Power Plants

Another way to establish the value of geologic CCS is through the application of a performance-based standard for GHG reductions from power plants. Senate Bill 1368 (Chapter 598, Statutes of 2006) established a standard of 1,100 pounds CO2 per megawatt-hour for electricity delivered to California. This standard applies to long-term financial commitments between electricity buyers and sellers for the purchase of electricity from out-of-state suppliers.

Under SB 1368, geologically sequestered CO2 does not count as a power plant emission. The California Energy Commission enforces compliance with this standard for publicly owner or municipal utilities, while the California Public Utilities Commission enforces the standard for the investor-owned utilities.

Renewable electricity sources by their very nature comply with the standard. However, the current regulations do not address whether CO2 sequestered at an EOR site would meet the criteria for successful sequestration. As a result, such projects may not receive credit for capturing and reducing CO2 emissions.

### II.2. Review Panel's Mandate

The official title of the panel is "the California Carbon Capture and Storage Review Panel". It has been created to advise the California Energy Commission, the California Public Utilities Commission, the Air Resources Board, the Department of Conservation and other state agencies on CCS policy.

Panel members were chosen because of their strong interest and record of accomplishment in developing energy and environmental public policy. The goals of the Panel and its supporting advisory team will be to:

- Identify, discuss and frame specific policies addressing the role of CCS technology in meeting the State's energy needs and greenhouse gas emissions reduction strategies for 2020 and 2050; and

- Support development of a legal/regulatory framework for permitting proposed CCS projects consistent with the State's energy and environmental policy objectives.

*II.2.a Meetings*

1. April 22, 2010
2. June 2, 2010
3. August 18, 2010

*II.2.b. Testimony*

4. List in Appendix

*II.2.c. Written Comments*

5. List in Appendix

*II.2.d. Technical Advisory Committee Support*

6. List of papers in Appendix

## III. California Policy Context for CCS

### III.1. Current State Policy

Assembly Bill 1925, (Blakeslee, Chapter 471, Statutes of 2006), passed unanimously by the California Legislature, aimed to provide policy makers with an assessment of the present level of development of carbon capture and sequestration (CCS) technology and its potential application to meeting California's climate change mitigation goals. This bill directed the California Energy Commission (Energy Commission), in coordination with the Department of Conservation, to prepare a report for the Legislature that contained:

> . . . recommendations for how the state can develop parameters to accelerate the adoption of cost-effective geologic sequestration strategies for long-term management of industrial carbon dioxide.

However, it remains unclear how CCS fits into California's overall strategy or policy to reduce its GHG emissions. The overall goals were established by Governor Arnold Schwarzenegger and the California Legislature on June 1, 2005 when the Governor signed Executive Order S- 3-05, which established three target reduction levels for GHG emissions in California: 2000 levels by 2010; 1990 levels by 2020; and 80 percent below 1990 levels by 2050. Upon passage of Assembly Bill 32, the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006), California began to identify ways to meet the second target of reducing GHG emissions to 1990 levels by 2020. AB 32 programs are administered by the California Air Resources Board (ARB), and include the low carbon fuel standard (LCFS), the cap-and-trade program and regulations for GHG accounting and reporting. Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), followed with a mandate for new or renewed long-term contracts to purchase electricity from baseload facilities to meet the GHG emission performance standard (EPS) established by the California Public Utilities Commission (CPUC) and the Energy Commission, in consultation with the Air Resources Board (ARB).

#### *III.1.a. Emissions Performance Standard*

The $CO_2$ EPS for baseload generation owned by, or under long-term contract to the state's utilities is 1,100 lbs $CO_2$/MWh. The Energy Commission and the CPUC implement this standard and it is a separate process from the AB 32 regulations. The current regulations implementing SB 1368 allow for the use of CCS to meet the EPS, but the details for determining compliance are unclear. The CEC regulation states that for covered procurements that employ geologic $CO_2$ sequestration, the successfully sequestered carbon dioxide emissions shall not be included in the annual average $CO_2$ emissions. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. $CO_2$ emissions shall be considered successfully sequestered if the sequestration project meets the following requirements:

- Includes the capture, transportation, and geologic formation injection of $CO_2$ emissions;
- Complies with all applicable laws and regulations; and
- Has an economically and technically feasible plan that will result in the permanent sequestration of CO2 once the sequestration project is operational

These requirements differ from AB 32 requirements in a few key ways. First, the EPS is based on emissions over the lifetime of the plant whereas AB 32 is based on annual emissions and the low carbon fuel standard (LCFS) considers life-cycle emissions (including indirect emissions). Second, the EPS requires an economically and technically feasible plan for permanent sequestration while AB 32 accounting would need a quantification methodology for any emissions and to verify permanent sequestration. The definition of permanent sequestration is not included and may have different criteria than those defined under the AB 32 regulations.

Within California, studies of strategies for future GHG reductions to meet either the 2020 goals of AB 32 or the longer term goals of Executive Order S-3-05 generally have not included CCS options. An example is the Energy Commission's scenario analysis of California's electricity system. Although the rate of deployment of geologic CCS is probably too slow for consideration of this technology in policy decisions over the period to 2020, over the longer term to 2050, geologic (and terrestrial) sequestration within California, the Western Electricity Coordinating Council (WECC), and the Western Climate Initiative (WCI) partner region should be incorporated into any evaluations to understand how policy and technology can achieve GHG goals while continuing to provide fuels and power at the lowest possible cost to Californians.

### *III.1.b. Low Carbon Fuel Standard*

The Low Carbon Fuel Standard (LCFS) is one part of ARB's goal to meet the 2020 goals outlined in AB 32. Executive Order S-1-0712 requested ARB create an LCFS. The order calls for a reduction of at least 10 percent in the carbon intensity of California's transportation fuels by 2020. The LCFS is separate from Mandatory Reporting and the Cap-and-Trade Program; it has its own reporting tools and offset requirements.

The LCFS framework is based on the premise that each fuel has a "life-cycle" GHG emission value that is then compared to a standard. This life-cycle analysis represents the GHG emissions associated with the production, transportation, and use of low carbon fuels in motor vehicles. The life-cycle analysis includes the direct emissions associated with producing, transporting, and using the fuels. In addition, the life-cycle analysis considers other effects, both direct and indirect, that are caused by the change in land use or other effects. For some crop-based biofuels, the LCFS has identified land use changes as a significant source of additional GHG emissions.

The standards are expressed as the carbon intensity of gasoline and diesel fuel and their alternatives in terms of grams of carbon dioxide equivalent per megajoule (gCO2E/MJ). Providers of transportation fuels must demonstrate that the mix of fuels they supply meet the LCFS intensity standards for each annual compliance period. They must report all fuels and track the fuels' carbon intensity through a system of credits and deficits. Credits are generated from fuels with lower carbon intensity than the standard. Deficits result from the use of fuels with higher carbon intensity than the standard. A regulated party meets its compliance obligation by ensuring that the amount of credits it earns (or acquires) is equal to or greater than the deficits it has incurred. Credits may be banked and traded within the LCFS market to meet obligations.

ARB is developing a secure on-line LCFS Reporting Tool (LRT) to support the reporting requirements of fuels and other data to the state. ARB will review the reports for completeness and accuracy, evaluate the data to determine compliance, and conduct field investigations and audits to verify and validate the information.

CCS is specified as an option for producers of High Carbon Intensity Crude Oil (HCICO) to reduce emissions for production and transport of crude oil to less than 15 gCO2e/MJ. CCS could be considered when used for the production of alternative fuels such as hydrogen, compressed natural gas (CNG), or electricity. For CCS to be incorporated into the LCFS, a quantification methodology would be necessary.

### *III.1.c. Cap-and-Trade and Mandatory Reporting Regulations*

A 2007 report released by the Governor's Market Advisory Committee to the ARB contains the first published recommendations on the design of a cap-and-trade system to reduce GHG emissions in California. This report outlines the various opportunities and challenges of different design elements in an emissions trading program. A main purpose of a cap-and-trade program is to bring about low-cost emissions reductions within the sectors covered by the program. A cap limits emissions and creates a market for trading GHG emissions allowances where every ton of emissions has a price. This price provides a signal for developing new technologies that can reduce GHG emissions. An entity that adopts a new technology to reduce its emissions will have to hold fewer allowances. The report outlines four different options for defining the scope of a California GHG cap-and-trade program, but does not explicitly consider CCS options. The program options differ in their coverage of $CO_2$ emissions from fossil fuel combustion in California, proposed points of regulation, and the infrastructure required for program administration, but they all require a provision to address emissions associated with imported electricity. All of the options create price signals for CCS, the strength of which would depend on the relative costs of allowances compared to costs to implement CCS.

In November 2009, the California Air Resources Board (ARB) released preliminary draft regulations for a cap-and-trade program. The program relies on standardized methods established by the Mandatory Reporting Regulation (MRR) of 2007 (effective January 2009) to provide the source emissions data to support trading. Consistent with AB 32, ARB must adopt the cap-and-trade regulation by January 1, 2011, and the program itself must begin in 2012.

California also is working closely with six other western states and four Canadian provinces through the Western Climate Initiative (WCI) to design a regional cap-and-trade program that can deliver GHG emission reductions within the region at costs lower than could be realized through a California-only program. To that end, the ARB rule development schedule is being coordinated with the WCI timeline for development of a regional cap-and-trade program.

The WCI design documents do little to further the inclusion of geologic CCS as a technology for adoption before 2020. The WCI analysis assumed that no carbon capture and storage for electric power generation will be built prior to 2020. Further mention of CCS is made only as a footnote in the context of early reduction allowances (ERA), in which, for carbon capture and storage projects to qualify, the WCI partner jurisdiction must (a) have in place monitoring and verification requirements that are sufficient to enable the partner jurisdiction to establish that the sequestration is permanent; (b) have the ability to assure that early reduction allowances will be replaced where a reversal occurs; and (c) apply these requirements to the applicable project.

In California, the MRR adopted by ARB provides standardized methods for entities to measure, monitor, report, and verify emissions. The standardized method allows for ARB to determine the validity and accuracy of the reported emissions, provides consistency across reporting entities, and, in a GHG reduction program, provides the key element to verify progress towards reduction goals. California's largest industrial GHG emitters reported their emissions and electricity retail providers and marketers reported electricity transaction information for the first time under the MRR in 2009. However, there is no reporting process or offset project protocol for CCS; therefore, it will not be included or creditable within the state in the currently proposed regulations, nor presumably qualify for ERA under the WCI plan.

The Cap-and-Trade preliminary draft regulations[1] propose a statewide cap on greenhouse gas emissions from included entities. One metric ton of carbon dioxide equivalent emissions equals one allowance. The total number of allowances created is equal to the cap set for cumulative emissions from all covered sectors for that year or group of years.

To set the trading system in motion, ARB would distribute allowances, or emissions permits, to capped entities. In addition to allowances, a limited amount of emission reductions from sources that are outside the cap coverage could be authorized; these reductions are called offsets. Both allowances and offsets, which are both types of compliance instruments, can be traded among entities. The most recent economic analysis estimates an allowance price around $21 per allowance in 2020.[2]

The Cap-and-Trade program will cover: starting in 2012, industrial sources emitting more than 25,000 MTCO2e/year and electricity generation starting in 2012; and, starting in 2015, transportation fuels, industrial combustion at facilities emitting less than 25,000 MTCO2e per year, and all commercial and residential fuel combustion of natural gas and propane. Sources will be required to surrender compliance instruments equal to their annual emissions at the end of each compliance period, each of which is proposed to be three years in length (2012–2014, 2015–2017, and 2018–2020). ARB staff is considering whether to shorten the compliance period to a year. The ARB will use the Mandatory Reporting Regulation data to determine which entities have a compliance obligation and how many compliance instruments each entity must surrender. An entity will have to offer allowances or offset credits for each metric ton it reports emitting.

Conceptually, CCS may play a role in the Cap-and-Trade program in one of two ways: (1) CCS could be applied to emissions of a capped source and be reported via the MRR; (2) a non-capped source could apply CCS to its emissions, producing an offset credit that could then be obtained by a capped entity. In both cases, however, the exclusion of CCS from the MRR means there is no methodology for reporting and thus, no way for CCS to be incorporated in cap-and-trade.

AB 32 requires offsets to meet rigorous criteria that demonstrate that the emission reductions are real, permanent, verifiable, enforceable, and quantifiable. Because offsets must occur at non-capped sources, any GHG reductions occurring through CCS at a capped facility would not be considered offsets. Carbon capture and sequestration occurring at non-capped sources might be considered for offsets if a CCS offset project protocol is approved by the Board. Under the current proposal, offset protocols must be approved by the Board after an environmental impact assessment is conducted in compliance with the California Environmental Quality Act (CEQA). Additionally, ARB would pursue an open review process, including public workshops and comment periods, for any offset protocol. A

[1] California Air Resources Board, November 24, 2009, Preliminary Draft Regulation for a California Cap-and-Trade Program, http://www.arb.ca.gov/cc/capandtrade/meetings/121409/pdr.pdf

[2] ARB's Updated Economic Analysis of California's Climate Change Scoping Plan.

CCS project protocol is not among the present set of considerations, but it could be added for future years. The process for developing future protocols is not set but may follow the current approach of adapting a rigorous methodology developed by another entity. Any methodology developed outside of the AB 32 program must be revised to make it compliance grade for AB 32 and consistent with ARB regulations. The current proposed draft regulation would allow offsets for up to 4 percent of a source's compliance obligation, ensuring that at least half of the emissions reductions come from the capped sources themselves.

### *III.1.d. GHG Accounting under AB 32 vs. Other Guidelines*

The U.S. Environmental Protection Agency, European Union, Intergovernmental Panel on Climate Change, non-profits, industry organizations, and others are developing or have developed national and international accounting guidelines or systems for CCS; however, any and all of them would need to be revised to be compliance-grade for ARB's programs. The revisions process would be public and include technical and policy changes to ensure that the quantification methodology is appropriate for California conditions including consistency with the MRR and Cap-and-Trade Regulation as well as considering any changes that may need to be made to account for different risks due to California geology and seismicity concerns.

Accurately accounting for carbon dioxide captured, transported, and sequestered is necessary for ARB to ensure that the sequestered CO2 can be quantified and verified as permanent. Both the reductions and emissions from the mitigation technology would need to be considered. Reporting and offset methodologies must be consistent and rigorous enough to support a trading system.

Unlike the Division of Oil, Gas, and Geothermal Resources' (DOGGR) current monitoring requirements, ARB's accounting methodologies must accurately quantify GHG emissions and reductions. Any accounting scheme also must identify and quantify leakage to the atmosphere. A monitoring program designed purely for the purposes of health and safety or to protect drinking water would likely not be sufficient for emissions and reduction regulation, wherein every ton of CO2 leaked to the surface or lost as fugitives at a compressor or wellhead has to be quantified.

Measurement, monitoring, verification, and reporting must occur through ARB's system in order to ensure consistent application and compliance with overall AB 32 programs. AB 32 requires ARB to monitor, verify, and enforce the greenhouse gas Mandatory Reporting Regulation as well as ensure that any greenhouse gas reductions are accurate, permanent, and verifiable. ARB's approach has been to develop sector-based rather than project-based accounting requirements.

Carbon capture and sequestration brings unique considerations to GHG accounting as it includes reductions and emissions that cross sectoral boundaries. Reductions occur at an industrial facility but emissions occur both at the facility during capture and elsewhere as the carbon dioxide is transported, compressed, and injected into the subsurface. Additionally, the sequestration site would need to be able to verify that the reductions are permanent.

Enhanced oil recovery with sequestration would present more complexity because emissions can occur in the production, recycling, and reinjection phase. The subsurface might also require monitoring to verify the absence of migration to other producing sites or old wells.

Some fundamental questions arise when considering how CCS might be accounted for under AB 32 regulations:

- What level of measurement/monitoring certainty would be enough? (Currently the Mandatory Reporting Regulation has established a +/- five percent standard for the measurements that generate fuels emissions estimates.)
- Would a monitoring plan need to be able to detect a leak of x amount with x likelihood? (e.g., if a leak were detected, would it need to be quantified within +/- five percent?)
- Can current monitoring techniques quantify leaks with enough accuracy and precision?
- If measurement accuracy and precision is not high enough, would it be sufficient to incorporate the uncertainty into the emissions and reductions accounting?
- How would permanence be addressed? (Within the current Cap-and-Trade program, if reductions or removals may be reversible (e.g., there could be an emissions leak), mechanisms must be in place to replace any reversed carbon. The operator must ensure that credited reductions endure for a period comparable to the atmospheric lifetime of anthropogenic $CO_2$ emissions. Permanence is also being addressed in each protocol.)
- Who verifies the emissions and reductions? (Under Cap-and-Trade, ARB requires verification statements from third party verifiers for both reporting and offsets.)

## III.2. Perspectives on the Role of CCS in California

### *III.2.a. Industry Perspectives*

#### *III.2.a.(i). Oil & Gas Industry*

**Possible compliance paths**

**Benefits and GHG Impacts of CO2-EOR**

#### *III.2.a.(ii). Power Generation, including commentaries on the need to utilize end use efficiency, demand response, and renewable energy systems to achieve long-term AB32 goals*

**Application to natural gas-fired generation**

#### *III.2.a.(iii). Other Industries (Cement; beneficial reuse)*

**Introduction:**

In addition to using $CO_2$ for enhanced oil recovery (EOR), there are many other possibly beneficial and revenue-generating uses for captured $CO_2$ in various stages of development. Technologies using CO2 might advance greenhouse gas (GHG) reduction goals by either preventing the captured $CO_2$ from entering the atmosphere, or by using the $CO_2$, or a chemical product produced from $CO_2$, in a way that displaces the emission of other GHGs.

### Background:

To date technologies making beneficial use of $CO_2$ such as EOR have had a negligible impact on overall anthropogenic $CO_2$ emissions. The volumes of the current merchant and captive $CO_2$ markets combined amount only to about 1% of global anthropogenic $CO_2$ emissions.[3] [4] Furthermore the current market demand for $CO_2$ is mostly addressed by geological sources of $CO_2$ (including essentially all of the $CO_2$ used in EOR);[5] the use of which provides no reduction in GHG emissions to the atmosphere. The majority of $CO_2$ in the merchant market[6] is used for EOR (~70-80%),[7] along with a significant portion used in the food processing industry. $CO_2$ in captive chemical processes[8] is most commonly used in the production of urea ($(NH_2)_2CO$) for fertilizer.[9] $CO_2$ currently being utilized that has been separated from flue gas or chemical process streams is generally either captured from relatively pure flue gas streams (e.g. ethanol distilleries) or from process streams where $CO_2$ capture and separation is necessitated by a need for product purity (e.g., natural gas pipelines or ammonia production). Only about 2% of the demand for $CO_2$ is currently met through capturing $CO_2$ from power plant or industrial flue gas streams, which have relatively dilute $CO_2$ content and no current requirement for $CO_2$ capture and separation.

New technologies that facilitate the use of $CO_2$ could increase the demand for $CO_2$ captured from power plant and industrial sources, improving the economic viability of $CO_2$ capture, and reduce GHG emissions, while providing useful products to the public. Technologies making use of $CO_2$ could possibly provide other positive environmental and economic benefits as well including reduced water consumption, replacement of toxic chemicals, and displacement of imported fuels, chemicals or minerals. Some of the technological possibilities for $CO_2$ use will be discussed in Section 0
The importance of finding value for $CO_2$ independent of any proposed regulation, carbon credit markets, or carbon taxes has been stressed in previous studies including the AB 1925 report to the California legislature "Geologic Carbon Sequestration Strategies For California: Report To The Legislature"[10] and the 2009 Integrated Energy Policy Report published by the California Energy Commission.[11] The example of Hydrogen Energy California (HECA) illustrates how a commercial scale carbon capture project at a fossil-fired power plant can move forward in California under the current regulatory environment, without the existence of carbon credits or carbon taxes, if it is linked to a promising and potentially economical use for the captured $CO_2$; although it should be noted that HECA, like many new alternative energy projects, has received government support including $308 million from the Department of Energy (DOE) through the American Recovery and Reinvestment Act of 2009 (ARRA). In the case of HECA the captured $CO_2$ will be delivered by pipeline to Occidental Petroleum's Elk Hills oilfield for EOR, which is a relatively well established and understood use of $CO_2$. However there is a need for new, alternative uses of captured $CO_2$ since EOR will not be appropriate for all carbon capture operations and locations, nor will EOR be able to absorb all of the $CO_2$ that could potentially be captured from industrial point sources.



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[3] Intergovernmental Panel On Climate Change, *Carbon Dioxide Capture and Storage: Chapter 7 Mineral carbonation and industrial uses of CO2.* Cambridge University Press, UK. 2005.
[4] Tiina Koljonen, Hanne Siikavirta, Ron Zevenhoven, *CO2 Capture, Storage and Utilization in Finland*, Project Report, VTT Processes, Systems and Models, Aug. 29, 2002, www.vtt.fi/inf/julkaisut/muut/2002/co2capt.pdf
[5] H. Audus, H. Oonk, 1997, *An assessment procedure for chemical utilization schemes intended to reduce CO2 emission to atmosphere*, Energy Conversion and Management, 38 (suppl, Proceedings of the Third International Conference on Carbon Dioxide Removal, 1996), S 409- S 414
[6] Market in which $CO_2$ is bought and sold competitively by multiple market participants
[7] Ibid. 2
[8] $CO_2$ produced onsite by the user of the $CO_2$ and not sold to outside customers.
[9] Ibid. 1
[10] http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF
[11] http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

## Technology Overview :

### *$CO_2$ Use With Geological Storage:*

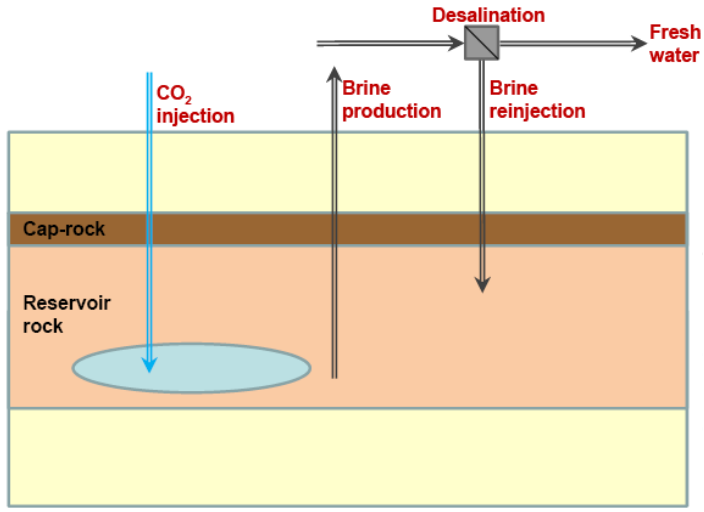


Figure 1 Desalination of aquifer brines displaced by CCS to create fresh water. Source William Bourcier, LLNL.

At the August 18th Carbon Capture and Storage (CCS) Review Panel Meeting Dr. William Bourcier from Lawrence Livermore National Laboratory discussed coupling geological storage (GS) of $CO_2$ to the production of brine under high pressure, which may allow relatively inexpensive production of fresh water from brine through reverse osmosis.[12] This is an example of a possible $CO_2$ use (Figure 1). In addition to fresh water, it is possible that valuable minerals such as lithium, used in rechargeable batteries, could be economically recovered from some brines.

Other technologies joining GS to some useful product that are being researched include enhanced gas recovery (EGR) with GS (Figure 2), and enhanced geothermal systems using $CO_2$ (EGS-CO2), instead of water, as a heat exchange fluid (Figure 3). [13] Both of these technologies resemble EOR in that they provide a dual benefit of additional energy generation combined with GS. However instead of being joined to the recovery of oil, GS is joined to the enhanced recovery of natural gas or geothermal heat for EGR and EGS-CO2 respectively. The company GreenFire Energy, a member of the West Coast Regional Carbon Sequestration Partnership (WESTCARB),[14] is attempting to commercialize EGS-CO2 technology with a demonstration plant planned near St. Johns Dome in New Mexico and Arizona.

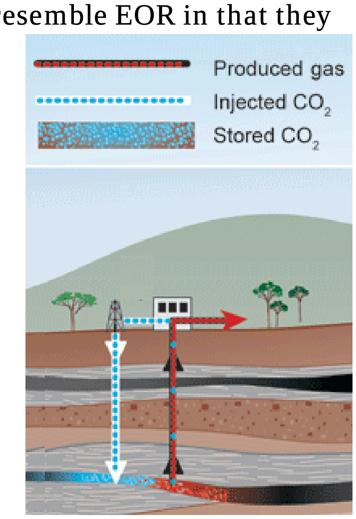


Figure 2 Enhanced coal bed methane recovery. Source CO2CRC; IPCC, 2005

### ***$CO_2$ Use With Non-Geological Storage***

As mentioned in the AB 32 Scoping Plan published by the California Air Resources Board there are other strategies for preventing the release of $CO_2$ into the atmosphere in addition to GS, such as the industrial fixation of $CO_2$ into inorganic carbonates.[15] Technologies are being developed today that synthesize solid materials such as plastics, or carbonates that can be used in cement or construction materials, from a $CO_2$ feedstock. A number of companies are trying to commercialize technologies for converting CO2 into carbonates including WESTCARB member Calera Corporation based in Los Gatos.

[12] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-08-18/presentations/01_Bourcier_Cal_CCS-Panel.pdf
[13] Donald Brown, "*A Hot Dry Rock Geothermal Energy Concept Utilizing Supercritical CO2 Instead Of Water*", Proceedings, Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA, Jan 24-26, 2000
[14] The California Energy Commission organized and leads the WESTCARB partnership, and, along with DOE, is a principal funder of its work. www.westcarb.org
[15] http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

All of the examples given in Section 0 and 0 represent technologies that may someday help advance GHG reduction goals by storing $CO_2$ long-term, while providing additional benefits and useful products to the public.

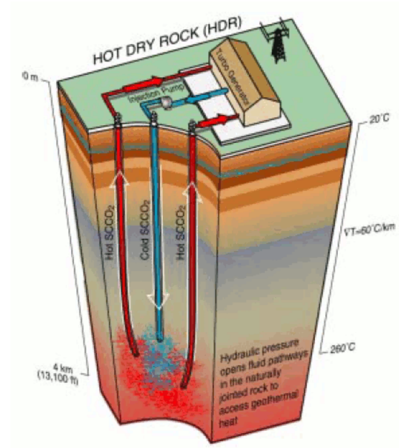


Figure 3 Enhanced geothermal system using supercritical CO2. Source Donald Brown, LANL.

### *$CO_2$ Use Without Long-Term Storage*

There are other technologies under development that do not provide long-term storage of $CO_2$, but which still could reduce overall GHG emissions by either 1) using $CO_2$ in a way that displaces the emission of other GHGs, or 2) converting $CO_2$ into a chemical that can in turn displace the emission of other GHGs. An example of the former is using $CO_2$ as a refrigerant that substitutes for chemicals currently used in refrigeration that are far more potent greenhouse gases than $CO_2$, such as hydrofluorocarbons (over 1000X stronger greenhouse effect per unit volume than $CO_2$). An example of the latter is the wide array of "CO2-to-fuel" technologies being researched with the goal of producing liquid fuels ranging from methanol or ethanol to gasoline or diesel out of $CO_2$ and water, along with an energy input (preferably from a $CO_2$-free source such as solar or wind). Fuels produced from waste $CO_2$ might displace the use of petroleum-derived fuels, which could result in reduced net GHG emissions, as well as address security issues related to importing oil.

### *Summary Of Technologies*

These examples give just a few of the possible uses for $CO_2$. It is evident that the possible uses of $CO_2$ vary greatly, and cover a wide range of fields and applications. They also vary widely in their stages of development, from those being tested at the bench-scale, to technologies that are close to commercialization, as well as in their potential to impact overall GHG emissions.
The question of how much technologies that put $CO_2$ to useful purpose will be able to reduce net GHG emissions is an area of debate and uncertainty as illustrated by this quote taken from the 2005 Intergovernmental Panel On Climate Change Report Technical Summary:

> "Another important question is whether industrial uses of $CO_2$ can result in an overall net reduction of $CO_2$ emissions by substitution for other industrial processes or products. This can be evaluated correctly only by considering proper system boundaries for the energy and material balances of the $CO_2$ utilization processes, and by carrying out a detailed life cycle analysis of the proposed use of $CO_2$. The literature in this area is limited but it shows that precise figures are difficult to estimate and that in many cases industrial uses could lead to an increase in overall emissions rather than a net reduction."[16]

There is a need to better understand the viability of the various technological options for $CO_2$ use and their potential to incentivize industrial carbon capture and provide substantive GHG emissions reductions. Where research funding can be most effectively invested in this area to advance GHG reduction goals, given the many diverse types and stages of $CO_2$ use technologies, is an important question that the Energy Commission is preparing a research roadmap to address.

[16] Intergovernmental Panel On Climate Change, Carbon Dioxide Capture and Storage: Technical Summary. Cambridge University Press, UK. 2005.

### Policy Options on $CO_2$ Use

Given the many existing and potential uses of $CO_2$, one option to consider would be for California to declare that $CO_2$ is a commodity, as other states have done including Louisiana (HB 661 2009).[17] This would follow the recommendation of the "Storage of Carbon Dioxide in Geologic Structures - Legal and Regulatory Guide for States and Provinces"[18] published by the Interstate Oil and Gas Compact Commission (IOGCC) of which California is a member. However declaring $CO_2$ to be a commodity could have implications on how, and by which agencies $CO_2$ capture and use is regulated, which need to be analyzed in detail.

In public comments received by the California CCS Review Panel there has been an expressed desire that non-geological sequestration strategies, such as the conversion of $CO_2$ to carbonates, be formally recognized as a viable sequestration option, and that there be a more explicit recognition that CCS is broader than simply gas separation and geologic storage.[19] These comments also highlight how concerns involved with non-geological types of sequestration and $CO_2$ use will likely have different policy interests and priorities than ones involved with GS.

For uses of $CO_2$ that involve GS such as the enhanced recovery of natural gas, geothermal heat, minerals, or water, it would appear possible that such technologies could be treated under a similar policy framework as EOR joined to CCS (CCS/EOR). However, it has been found that there may be significant differences between CCS/EOR and CCS in saline formations e.g. differences in monitoring, measurement, and verification (MMV), possible differences in UIC well classification, as well as possible differences in state permitting agencies. One can reasonably foresee that each type of enhanced recovery of a geological resource joined to GS would likely have its own set of unique requirements as well.

The differences between $CO_2$ use technologies that generally involve GS (e.g. Section 0), and those that do not (e.g. Sections 0 and0), are even more significant, and one would expect that to be reflected in the policy priorities associated with each respective technology type. For example in the case of carbonate materials made using $CO_2$, many of the significant issues that confront GS such as long-term stewardship, liability, and risks associated with storage are far less of a worry.[20] This is due to carbonates generally being solid, highly thermodynamically stable compounds. However, carbonates could still have their own unique accounting issues since carbonates can react over time releasing $CO_2$ under certain conditions (e.g. acidic environments), so sequestration over the long term could be less than the $CO_2$ initially captured.

There are policy issues confronting the non-GS strategies that could be addressed to help them advance. For example, it has been proposed that the state could help create a market that establishes value for $CO_2$ mitigation through a policy framework that resembles what has been implemented for renewable power with the Renewable Portfolio Standard (RPS).[21] It has also been suggested that sources creating $CO_2$ neutral or negative products should get reduction or offset credits not only for the emissions prevented at their facilities, but also for those that would have resulted in the use of carbon intensive conventional materials.[22]

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[17] http://www.legis.state.la.us/billdata/streamdocument.asp?did=668800
[18] http://groundwork.iogcc.org/sites/default/files/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf
[19] http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-06-02/comments/Calera_Comments.pdf
[20] Ibid. 1
[21] Ibid. 19
[22] Ibid. 19

The idea of getting credit for emissions avoided that would have resulted from the production of conventional products is very relevant to all of the $CO_2$ use technologies that do not sequester the $CO_2$, such as CO2-to-fuel technologies. The claimed GHG reduction for these technologies generally rests on a comparison to a “business as usual case” e.g. a car burning diesel made from $CO_2$ captured from flue gas versus one burning diesel made from petroleum. In both cases $CO_2$ is emitted from the tail pipe but the former case could result in less net $CO_2$ emissions than the latter business-as-usual case when accounting for both flue gas and tailpipe emissions combined. Further complicating matters is the importance of the source of the $CO_2$ in this accounting. For example $CO_2$ captured from a fermentation process at an ethanol refinery is made from carbon absorbed from the air through photosynthesis, while the carbon from $CO_2$ captured at a coal plant is from underground. The California Low Carbon Fuel Standard provides a model for addressing these kinds of life-cycle carbon intensity questions in a way that could be applied to emerging CO2-to-fuel technologies,[23] [24] as well as in a more general sense to other $CO_2$ use technologies that displace the emissions of other GHG rather than sequester $CO_2$.

## III.3. Suitable Geologic Formations in California [Burton]

The suitability of a site for CCS depends on its proximity to sources, the suitability of the source plant for capture infrastructure, options for transport of $CO_2$, and whether the subsurface geology is suitable for safe and adequate storage. The focus of this section is on summarizing the assessments to date of the suitability of the subsurface in California, with less emphasis on sources and transport. However, deployment of widespread CCS in the state will require integrated assessments which include engineering analysis of sources, analysis of pipeline, rail, or other transportation alternatives, and geologic characterization. One such preliminary assessment is in progress by WESTCARB, focused on existing and newly permitted NGCC power plants. Any energy infrastructure planning or assessments done by the state which include fossil fuel sources could also include provision for such integrated CCS assessments.

The material presented here relies primarily on the summary of California’s potential for storage in the Assembly Bill 1925 report[25], on reports done for WESTCARB by the California Geological Survey[26], and on white papers and presentations prepared for the Panel.[27]

### *III.3.a Sources*

For 2004, the state’s GHG inventory shows that fossil-fuel combustion for electricity generation within California emitted about 47 MMT $CO_2$/year, mostly from natural gas plants, and fossil fuel combustion in the industrial sector totaled about 67 MMT $CO_2$/year.[28] Within the industrial sector, the largest point sources are oil refining and cement production, creating about 18 MMT $CO_2$ per year, and about 12 MMT $CO_2$ per year respectively.[29] The $CO_2$ emissions estimates for refineries and

[23] http://www.arb.ca.gov/fuels/lcfs/lcfs.htm
[24] http://www.energy.ca.gov/low_carbon_fuel_standard/
[25] AB 1925 report
[26] CGS reports
[27] Myer and Bruno presentations.
[28] GHG inventory.

[29] Herzog, H.J., 2005, op. cit.

cement plants are from a WESTCARB study[30] and are difficult to compare with the data in the GHG inventory for California because the state's inventory accounting methods divide point source emissions according to the origin of the $CO_2$ generation. For example, cement plant emissions are separated into parts attributable to cement production and to use of various fuels, and, for refineries, into components such as emissions from use of natural gas, distillate, or residual oil. The WESTCARB study focused on quantifying total emissions from specific plants or point sources and summed these emissions to estimate the total for a sector.

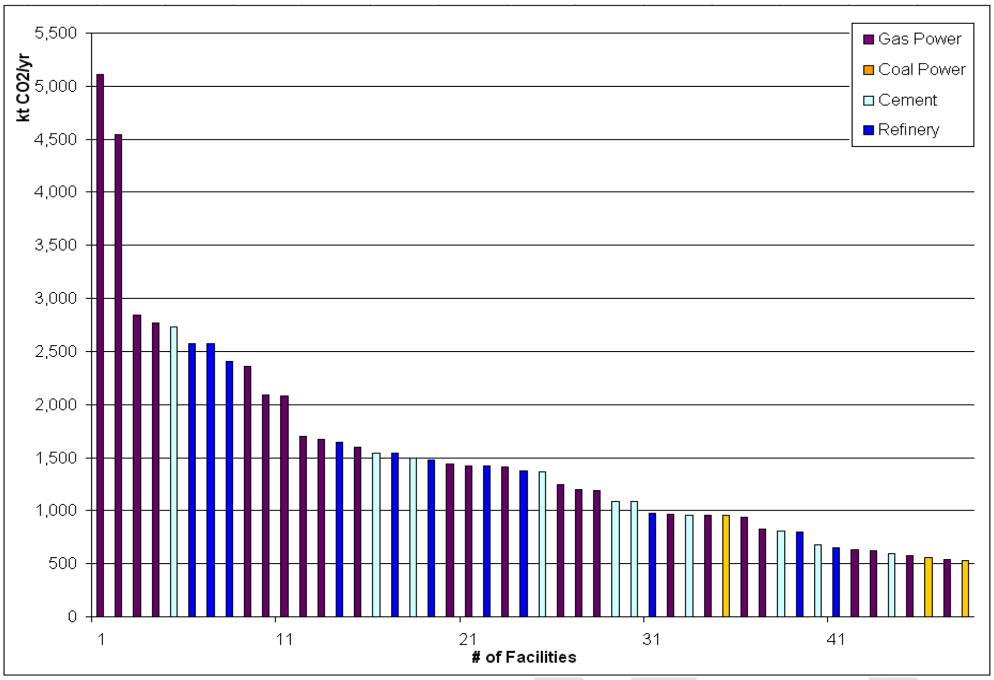
For the power sector, it is important to note that emissions counted in the state's inventory include in-state and out-of-state GHG emissions. Power plant emissions, based on the GHG emissions inventory, totaling about 108 million metric tons $CO_2$/year (61 out-of-state, and 47 in-state), could all theoretically be geologically sequestered. However, practicality and economics limit CCS to that part of the emissions inventory associated with large single point sources, such as stacks on factories or power plants. Capture would be impractical, for example, for transportation fuel emissions, California's largest sector source at about 190 million metric tons of $CO_2$ per year, because the emissions come from millions of small mobile sources. Plans for $CO_2$ emissions reduction in the transportation sector typically focus on using lower net carbon fuels, such as ethanol, or electric-powered vehicles, which would shift emissions from the transport to the power sector.

Within the spectrum of large point sources in California, effective deployment of CCS to achieve the greatest impact on the state's GHG emissions might be best focused initially on the largest of these point sources (Figure 1). By 2050, assuming moderate economic growth, achieving the 2050 target level of about 90 MMT/year would require reducing emissions by 10 MMT/year each year starting in 2010, or 14MMT/year starting in 2015.[31] Even with policies which provide an economically favorable case for adoption of CCS, the rate of deployment may still be limited by factors such as insufficient understanding of the sequestration resource potential and by the pace of transport and other infrastructure development.

**Figure 4: Largest Specific California $CO_2$ Sources by Type and Size**

[30] Herzog, H.J., 2005, op. cit.

[31] CIEE study




Source: Katzer, J. and Herzog, H., 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California*, E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

Figure 1 shows that there are about 30 existing facilities in California each emitting more than 1 million metric tons of $CO_2$ per year. Most are natural gas-fired power plants, along with several oil refineries and cement kilns. The few coal- and petroleum coke-fired power plants in California are relatively small as they are mostly non-utility generators built as cogeneration qualified facilities under previous regulations that limited their size to less than 80 megawatts. A future exception will be the HECA plant, scheduled to be online in 2015, which will use coal and gasification of petcoke and coal to provide hydrogen for 250 MW of electric power generation and which will produce about 2 million tons of $CO_2$/yr to be captured and piped to Occidental's Elk Hills Field for enhanced oil recovery.

Another potentially significant source of emissions in the state is ethanol plants. While emissions today total less than 1 million metric tons per year from a few ethanol plants, the number of plants in the state could rise significantly, presuming sustained favorable biofuels policies and financing. These plants offer the potential for using CCS to create "net negative" $CO_2$ emissions because biomass derived fuels may be already nearly carbon neutral.

The largest $CO_2$ point sources within the state's inventory of emissions are related to California's imported electricity. Several of the coal-fired utility power plants in Arizona, New Mexico, and Utah that supply electricity to California produce emissions in the range of 4 to 20 million metric tons of $CO_2$ per year. These plants are under pressure to reduce GHG emissions to meet caps such as that set by California's Senate Bill 1368, which prohibits long term electricity contracts by public utilities with power producers emitting more than 1100lbs CO2/kwh.  They are also increasingly under pressure to reduce particulate emissions from the standpoint of air quality, a factor which led recently to the closure of the ------ in Arizona.  These types of pressures are likely to lead to a change in fuel from coal to natural gas rather than adoption of CCS. However, in the longer term, deeper GHG emissions reductions will require deployment of CCS. In this context, coordination of policies across the western region may optimize CCS.

### *III.3.b. Transport of $CO_2$*

Where large point sources do not overlie suitable sequestration sites, $CO_2$ may have to be transported via pipelines or on trucks, trains, ships, or barges. In today's commercial markets, $CO_2$ is routinely transported in tanker trucks as liquid $CO_2$ at 20 bars (290 pounds per square inch) and -20°C (-4°F); however, for the large quantities of $CO_2$ involved in CCS, tanker transport is impractical and uneconomic. Rail has been considered viable in some cases. However, pipelines are the likely mode of $CO_2$ transport for commercial-scale sequestration operations.

The technical, economic, and permitting issues associated with $CO_2$ compression and pipeline transport are well known in the U.S. because of the large-scale use of $CO_2$ for over 20 years in EOR operations in many other states. $CO_2$ is also transported via pipeline for a number of industrial uses in California and other states. Over 1,500 miles of $CO_2$ pipelines exist in the U.S. today with a capacity in excess of 40 MMT $CO_2$ per year.[32]

In these pipelines, $CO_2$ that is produced primarily from natural $CO_2$ reservoirs is transported as a dense, single phase at ambient temperatures and supercritical pressures. The $CO_2$ is typically compressed to 150 bar (2200 pounds per square inch) or more at its source. To maintain supercritical pressures, booster compressors may be necessary along the length of the pipeline. However, not all pipelines require recompression. For example, the Weyburn pipeline, which transports $CO_2$ about 200 miles from an industrial facility in North Dakota to an EOR site in Saskatchewan, Canada, operates without a recompression system.[33] To avoid corrosion and hydrate formation, water levels are typically kept below 50 parts per million. To assure single phase flow, non-condensable gases (nitrogen and oxygen, for example) are removed, and pressures are kept in excess of the critical pressure for $CO_2$ (73.9 bar or 1070 pounds per square inch).[34]

### *III.3.c. Geologic Suitability*

In California, suitable geologic formations for $CO_2$ storage include depleted or near-depleted oil and gas reservoirs and saline formations (rocks containing non-potable salty water). These targets are common in deep sedimentary basins, places where sand and mud have accumulated to great thickness over many millions of years and lithified (compacted under pressure into rock). These types of layered rocks are potentially good storage sites because they have the capacity to hold or trap large amounts of $CO_2$ in the pore spaces of permeable layers such as sandstone, while overlying impermeable mud-rock layers form good seals that prevent the gas from escaping upward. Sequestration takes place optimally at depths below 2,500 feet (800 meters) where pressures and temperatures keep $CO_2$ in a liquid-like, supercritical phase. In this phase, $CO_2$ occupies the least volume per unit mass, and its density ranges from 50 to 80 percent of the density of water.

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[32] Katzer, J. and Herzog, H., 2008, "PIER white paper on Economics of $CO_2$ Capture and Sequestration," *Assessment of Geologic Carbon Sequestration in California,* E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009.

[33] Metz, B.E.A., ed., 2005, op. cit.

[34] Katzer, J. and H. Herzog, op. cit.

Both oil and gas reservoirs and saline formations derive from the same lithified sand and mud in a sedimentary basin, so the physical properties of the rocks of relevance to CO2 storage, such as the porosity and permeability of the sandstones, and impermeability of the mud-rock seals, are the same in both cases. Oil and gas reservoirs can be thought of as local regions within saline formations where hydrocarbons fill most of the pore space between the sand grains.

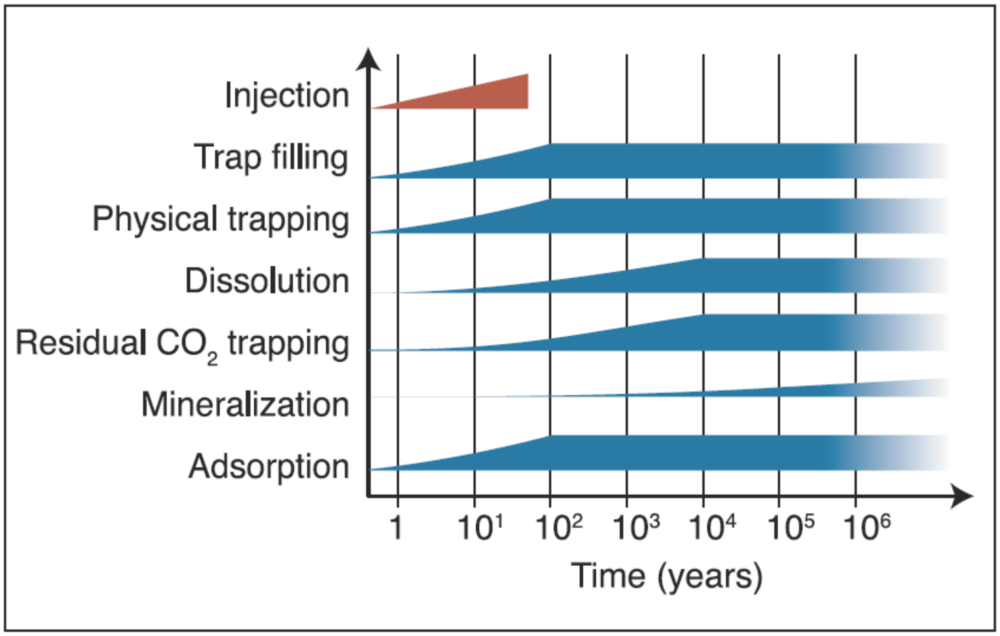
Other factors can potentially reduce the suitability of a site; these include the presence of leaky faults or old wells and the presence of groundwater of salinity low enough to be a potential water resource, typically defined by a cutoff of 10,000 mg/l total dissolved solids.

It is important to note that the presence of faults is not by itself a criterion for eliminating a site from consideration. Many faults in California have been inactive for millions of years, and in fact some provide structural traps for subsurface buoyant fluids such as oil and gas. In other cases, faults have experienced recent motion, and the impact of that on the leakage potential of a reservoir must be carefully studied.

In most sedimentary formations, the pore spaces of the rocks are occupied by highly saline waters, or brines; in some, other fluids, such as oil or natural gas, also may be present. Although supercritical $CO_2$ is much less buoyant than gaseous $CO_2$, it is still more buoyant than water, resulting in a tendency for the $CO_2$ to migrate upward. In the early stages of sequestration, the overlying seals and pore spaces of the reservoir trap the buoyant $CO_2$ physically (trap filling and physical trapping) as a separate fluid. Over time, some of the $CO_2$ also dissolves in the water and reacts chemically with the water and rock (dissolution, mineralization, adsorption), as shown in Figure 2. Over time, several additional trapping mechanisms work to immobilize the $CO_2$ in the reservoir, including physical (capillary trapping) and chemical (solubility and mineral trapping) processes. Collectively, these are referred to as “secondary” trapping mechanisms.

**Figure 5: Types and Timescales of $CO_2$ Sequestration Mechanisms**

Schematic shows the time evolution of various CO2 sequestration mechanisms operating in deep formations during and after injection. Time is shown on an exponential scale were $10^1$ is 10 years, $10^2$ is 100 years, and so on.




Source: Metz, B.E.A., 2005, *Special Report on Carbon Dioxide Capture and Storage*. Intergovernmental Panel on Climate Change, Cambridge University Press, Cambridge, England. <http://arch.rivm.nl/env/int/ipcc/pages_media/SRCCS-final/SRCCS_Chapter4.pdf>.

As part of its studies for WESTCARB, the California Geological Survey (CGS) developed a preliminary screening method to identify sedimentary basins with the greatest geologic potential for $CO_2$ sequestration.[35] The CGS initially identified and cataloged 104 sedimentary basins that underlie approximately 33 percent of the area of the state. These basins include oil- and gas-producing regions (Figure 3). The basins were then screened, using available data, to make preliminary determinations of their suitability for $CO_2$ sequestration. Accessibility was a screening factor, and thus, basins were excluded that lay under national and state parks and monuments, wilderness areas, Bureau of Indian Affairs administered lands, and military installations. Most of the excluded basins are located in eastern and southeastern California where there are few large industrial sources of $CO_2$. Geologic screening criteria included the presence of significant porous and permeable units to store large amounts of $CO_2$, thick and pervasive seals to restrict migration of $CO_2$, and sufficient basin depth to provide the confining pressure required to inject and store $CO_2$ in its high-density, low-volume supercritical phase.

For basins that passed the initial screening, available data were used to make preliminary determinations of potential sequestration resource capacity. A total of 27 basins met the screening criteria. Of these, the most promising for sequestration are 10 of the largest: the San Joaquin, Sacramento, Los Angeles, Ventura, and Salinas basins, followed by the smaller Eel River, La Honda, Cuyama, Livermore, and Orinda basins. These basins include potential sequestration sites in both

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[35] Downey, Cameron and John Clinkenbeard, 2006, *An Overview of Geologic Carbon Sequestration Potential in California*. California Energy Commission, PIER Energy-Related Environmental Research, CEC-500-2006-088.

depleted oil and gas reservoirs and non-hydrocarbon-bearing formations.[36] Favorable attributes of these basins include:

- Good geographic distribution relative to emissions sources
- Thick sedimentary fill with multiple porous and permeable zones
- Thick, laterally persistent sealing units
- Availability of good datasets to characterize the subsurface
- Numerous abandoned or mature oil and gas fields that might be reactivated for $CO_2$ sequestration or benefit from $CO_2$ enhanced oil and gas recovery operations

A $CO_2$ storage *resource* estimate is defined as the volume of porous and permeable sedimentary rocks that is most likely accessible to injected $CO_2$ via drilled and completed wellbores. $CO_2$ storage resource assessments do not include economic or regulatory constraints; only physical constraints that define the accessible part of the subsurface are applied.[37] Preliminary estimates of $CO_2$ sequestration resource capacity for these 10 basins are between 75 and 300 metric gigatons tons of $CO_2$. The saline formation storage resource numbers quoted above arise from estimates made with limited geologic data, and without any constraints due to technology, cost, or regulations. As both geologic and non-geologic constraints are added, storage resource values, while still quite large, will be decreased. This can be seen in the continued work by the California Geological Survey to better define the state's CO2 storage resource. The large range in sequestration resource capacity results from differences in methods for estimating capacity[38] and from uncertainties in geologic characterization due to incomplete data coverage. More precise assessment of the specific potential of these basins for $CO_2$ sequestration requires additional geological characterization, including detailed, formation-specific mapping to define the thickness, extent, and continuity of potential reservoir and sealing units.

Subsequently, the CGS completed mapping of offshore basins (Figure 3) and further assessment of selected onshore basins and formations in greater detail, including adding screening criteria such as the salinity of the formation water. Terralog Technologies also is undertaking a more detailed study of the Wlimington Graben, directly offshore from the Los Angeles and Long Beach Harbor area. More than 3000 feet of Pliocene and Miocene formations are present in this basin at a depth appropriate for $CO_2$ sequestration (about 3000 to 7000 ft). This zone is easily accessible yet geologically isolated from the nearby Wilmington Oilfield and onshore area. These studies demonstrate the importance of more detailed site characterization prior to defining the sequestration potential of an area, given the diversity and complexity of California's geology.

**Figure 6: Sedimentary Basins offshore California**



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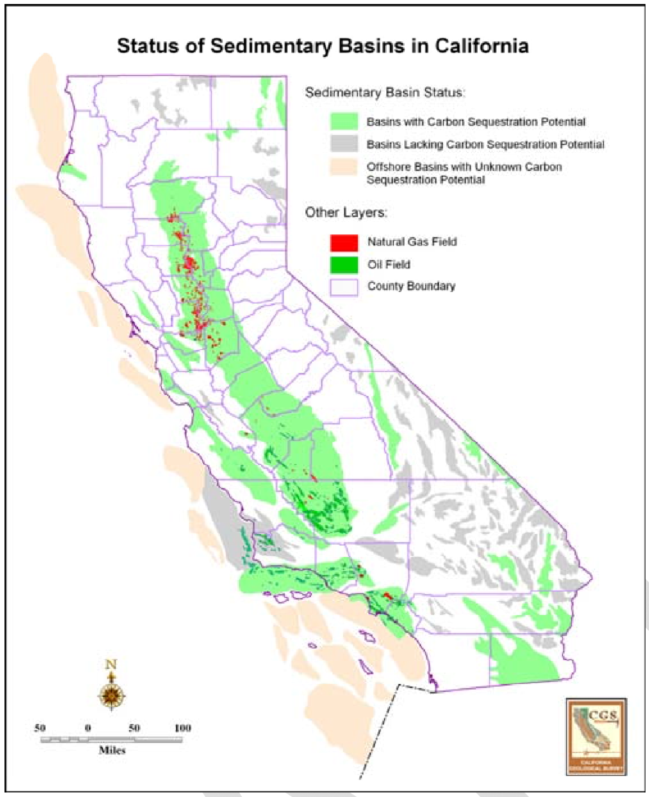
[36] Clinkenbeard, J., 2008, "Areas in California Potentially Suitable for Geologic Storage of $CO_2$," *Assessment of Geologic Carbon Sequestration in California*, E. Burton and R. Myhre, Eds. PIER Energy-Related Environmental Research, CEC-500-2008-009. .

[37] National Energy Technology Laboratory, 2008

[38] U.S. Department of Energy National Energy Technology Laboratory, 2007, *Carbon Sequestration Atlas of the United States and Canada.* <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/ATLAS.pdf>.




Source: Downey and Clinkenbeard, 2010.

Such characterizations also will likely require a substantial effort to obtain additional subsurface data through exploratory drilling and seismic surveys. For example, there are formations suitable for $CO_2$ storage in nearly all of the 20 offshore basins identified by the CGS, however, a lack of available data precludes the quantification of their $CO_2$ sequestration resource potential except in areas where oil and gas exploration has occurred. A CGS study of the oil and gas fields of the Los Angeles and Ventura offshore basins estimated 0.24 GT of capacity in depleted hydrocarbon reservoirs.

The CGS also has completed a more detailed, formation-specific mapping of the southern portion of the Sacramento Basin, representing a little more than 22% of the area of the Central Valley. This follow-on study provides an example of the effect of more detailed formation specific assessments on capacity estimates. This study evaluated three formations in the Sacramento Basin and added the salinity of formation water as a screening criterion. The CGS used information from about 6,200 wells to better define the thickness, extent, and continuity of potential reservoir sands and seals in the Mokelumne River, Starkey, and Winters formations and SP log data to determine salinity. Using the NETL methodology for calculation of $CO_2$ storage resource yielded a total of 3.5–14.1 GT for the mapped formations. On a percentage area basis, this represents about a factor of three decrease relative to the preliminary storage resource estimates. The addition of the salinity criterion resulted in a further volumetric decrease of 22% for the Mokelumne River Formation.

Resource capacity estimates are better constrained for the small, but important, subset of formations that contain oil and gas. Sequestration estimates are 3.5 gigatons of $CO_2$ for oil and 1.7 gigatons for natural gas reservoirs (Table 1).

Using the methodology developed to support NETL's Carbon Sequestration Atlas of the United States and Canada, the CO2 storage "resource" for the 10 onshore basins was calculated to be between 75 and 300 gigatonnes of carbon dioxide (GT CO2). For oilfields, preliminary estimates are on the order of 0.3 to 1.3 GT CO2, and for natural gas fields, from 3.0 to 5.2 GT CO2. The preliminary estimates indicate that the resource for geologic storage of CO2 is ample. For comparison, the CO2 emissions from power and industrial sources in California is currently about 0.08GT per year.

Many oil reservoirs in California, even those still actively operated, contain significant volumes of saline water which is co-produced with the oil.

**Table 1: Estimates of $CO_2$ Sequestration Resource Capacity in California in Oil- and Gas-Bearing Formations**

| **Type of Sequestration Reservoir** | **Number of Fields** | **Estimated Total Capacity (MMT $CO_2$)** |
|---|---|---|
| A: Oil Fields | | |
| Oil fields with $CO_2$ sequestration potential | 176 | 3,563 |
| Oil fields with miscible $CO_2$-EOR potential | 121 | 3,186 |
| Oil fields with immiscible $CO_2$-EOR potential | 18 | 178 |
| Oil fields with $CO_2$ sequestration capacity but no EOR potential (fields lacking American Petroleum Institute data also included) | 37 | 199 |
| Oil fields without $CO_2$ sequestration potential | 55 | 0 |
| Oil fields without depth information | 61 | 0 |
| B: Natural Gas Fields | | |
| Gas fields with $CO_2$ sequestration potential | 128 | 1666 |
| Gas fields without $CO_2$ sequestration potential | 36 | 0 |
| Gas fields without enough information | 33 | 0 |

Sources: Herzog, H.J., 2005, *West Coast Regional Carbon Sequestration Partnership $CO_2$ Sequestration GIS Analysis*. Topical Report West Coast Regional Carbon Sequestration Partnership (WESTCARB), DOE Contract No.: DE-FC26-03NT41984; Downey, Cameron and John Clinkenbeard, 2006, *An Overview of Geologic Carbon Sequestration Potential in California*. California Energy Commission, PIER Energy-Related Environmental Research, CEC-500-2006-088.

One geologic attribute that is necessary for the existence of oil and gas reservoirs, but not necessarily required for $CO_2$ storage because of secondary trapping, is structural closure, wherein geologic layers have been deformed or altered in a way that prevents lateral and upward movement of the hydrocarbons. The "classic" hydrocarbon reservoir is exemplified by seal rocks deformed into the shape of a dome, or inverted bowl under which the hydrocarbons have collected. In California, stratigraphic traps where the reservoir rock pinches out are common. Another very common structural closure mechanism in California is faulting in which permeable reservoir rocks on the low side of a steeply dipping fault are in contact with impermeable rocks by the displacement at the fault line, which prevents lateral movement of fluids. In some instances, however, faults can instead act as leakage paths. If faults are present, a necessary part of site characterization is to assess if they are seals or not.

It is important to note, however, that the degree of geologic isolation of the target formation may still be very high even when no hydrocarbons are present, although the evidence is less obvious. The chemical composition of deep saline waters indicates the degree of isolation of the formation from regional hydrodynamic systems. In some cases, these waters still retain the signature of the seawater that was originally trapped in the pore spaces of the sediments before lithification and deep burial, evidence of a degree of isolation even greater than that of many hydrocarbon-bearing structures.

Geologic sequestration in the subset of formations that have produced oil and natural gas for long periods offers several advantages. Because these formations are oil and gas-bearing, they have demonstrated, over geologic time, their ability to retain buoyant fluids like $CO_2$. In addition, through exploration and production activities, the subsurface geology in these areas usually is very well-characterized. Oil and gas operations have the appropriate infrastructure in place and require expertise similar to that needed for $CO_2$ injection. However, there are additional considerations when the CCS target is a formation where hydrocarbons are present, including statutory issues related to protection of mineral rights and ambiguities under existing frameworks as to how the project may be regulated.

Furthermore, a project may use the injected $CO_2$ to extract additional oil and gas from the formation, thereby creating a value for the $CO_2$. California has about 25,000 injection wells for oil and gas operations that, in 2005, injected some 3 billion barrels of fluids and approximately 250 million cubic feet of gas for enhanced oil recovery and disposal of wastes from oil and gas production.[39] Many of these wells are associated with EOR projects, but $CO_2$-EOR is extremely limited in California because the cost of transporting $CO_2$ into the state is prohibitive. Although it is not clear to what degree $CO_2$-EOR might supplant existing EOR approaches, $CO_2$ capture for sequestration creates a potentially economic supply of $CO_2$.

Although $CO_2$ injection to enhance oil recovery is a well established and proven technology, its use for enhanced natural gas recovery is relatively new. Methane recovery through $CO_2$ injection into coal beds has been field tested and studied in the laboratory with good results, suggesting there is also potential for enhanced gas recovery (EGR) from depleted gas reservoirs.

Although in both EOR and EGR, the $CO_2$ is left behind in the reservoir at the close of operations, the intention of these projects has not been to sequester $CO_2$. The Weyburn Oilfield in Saskatchewan, Canada, however, is a recent example of a $CO_2$-EOR project intended to conclude with sequestration of large quantities of industrial $CO_2$ from the Dakota Gasification Company's plant in Beulah, North Dakota. Over the life of the project, an additional 130 million barrels of oil may be produced, with net $CO_2$ sequestration estimated at 20 MMT.[40]

Relevant industrial experience includes natural gas injection and storage, which has been successfully practiced for many decades. For more than 30 years, the oil industry has re-injected produced gas for various purposes, including reservoir pressure maintenance, avoidance of sour gas processing in locations without markets for sulfur by-products, disposal of gas processing by-products, and to eliminate flaring. Similarly, salty water co-produced with oil is commonly re-injected. The oil industry also commonly uses CO2, water/steam, and nitrogen for enhanced oil recovery (EOR), wherein injected fluids mobilize residual oil to producing wells.

Final selection of a sequestration site in any of the California basins will require more detailed, site-specific data and detailed analysis of the subsurface. Thorough knowledge of the geologic structure and properties is key to minimizing the risk of leakage. From this perspective, storage locations in

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[39] <http://www.consrv.ca.gov/dog/general_information/class_injection_wells.htm>.

[40] International Energy Agency, *IEA GHG Weyburn $CO_2$ Monitoring and Storage Project,* n.d. <http://www.ieagreen.org.uk/glossies/weyburn.pdf>.

saline formations that are located vertically between, or laterally adjacent to, existing oil/gas reservoirs have an advantage over other locations because of the large body of pre-existing subsurface knowledge gained from the oil/gas exploration and production activities. A disadvantage of existing oil/gas reservoirs is that the existence of old wells, potentially not constructed or closed to modern standards, increases the risk of leakage. Generally, this risk increases with the age of the wells. Therefore, identification and assessment of existing deep wells at or near a proposed $CO_2$ storage project will need to be an element of site characterization.

*III.3.d. Summary*

Whether targets are depleted hydrocarbon reservoirs or saline formations, more detailed site characterization is critical and must be followed by detailed study of appropriate monitoring systems, potential health and environmental risks, transport issues, and economics.

Work to date has shown that the CO2 storage resource in California is ample and well matched with major industrial point sources. Saline formations represent the largest CO2 storage resource, by far. Depleted oil and gas reservoirs represent a smaller fraction of the total storage resource, but are attractive for early projects because of the greater availability of data for site characterization and the prospect of offsetting revenue from hydrocarbon sales. Though existing geologic data are generally more limited than for existing oil and gas reservoirs, saline formation storage is attractive because these formations are more broadly co-located with respect to GHG sources, and the risks of leakage from old wells is less.

It may be important to note that authority for permitting at present is split according to the type of storage formation: $CO_2$ storage in saline aquifers (and non-producing oil and gas fields requires federal EPA underground injection permitting (under Class I, Class V, or Class VI); $CO_2$ injection for enhanced oil recovery requires a California DOGGR injection permit (Class II).

Ultimately, saline formation storage will be necessary to accommodate all of the CO2 that must be captured from industrial point sources to enable California to meet its long-term goals for reducing greenhouse gas emissions. However, there currently is limited commercial incentive for $CO_2$ storage in saline aquifers.

## III.4. Health & Safety Issues and related history

*III.4.a. Human health considerations*

*III.4.b. Environmental considerations (specifically including, but not limited to, seismicity)*

## III.5. California CCS Policy Context in Comparison with Federal Developments and Activities in Other States

*III.5.a. Federal Overview*

*III.5.a.(i) Enacted Requirements*

**Source Emissions**

Stationary source emissions of greenhouse gases (GHG) are now subject to regulation under the federal Clean Air Act (CAA) (42 U.S.C. § 7401 et seq.) pursuant to the decision of the United States Supreme Court in *Massachusetts v. EPA*, 549 U.S. 497 (2007) which held that GHGs met the CAA's definition of "air pollutant."

Pursuant to the *Massachusetts v. EPA* decision, the U.S. Environmental Protection Agency (EPA) issued its so-called "Endangerment Finding" on December 15, 2009. 74 Fed. Reg. 66496 (Dec. 15, 2009). In the Endangerment Finding, EPA concluded that six GHGs – carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride – may reasonably be anticipated to endanger public health and welfare. On the same day, EPA issued what is known as its "Cause or Contribute Finding"; in that finding, EPA defined the applicant "air pollutant" as the same six GHGs, in aggregate, and found that this new "air pollutant," when emitted from new motor vehicles and new motor vehicle engines, contribute to GHG air pollution that endangers public health and welfare. Id.

On April 2, 2010, EPA published a notice that is known as the "Johnson Memo Reconsideration," 75 Fed. Reg. 17004 (April 2, 2010). In that notice, EPA interpreted the CAA term "subject to regulation," which is one of the regulatory triggers for permitting under the CAA's Prevention of Significant Deterioration (PSD) program. The Johnson Memo Reconsideration concluded that EPA's imposition of GHG tailpipe emission standards for certain mobile sources (which were subsequently published on May 7, 2010; 75 Fed. Reg. 25324 (May 7, 2010)) would trigger PSD applicability for GHG-emitting stationary sources on or after January 2, 2011, which is the date when the GHG tailpipe emissions standards took effect.

On June 3, 2010, EPA published what is commonly referred to as the "Tailoring Rule." 75 Fed. Reg. 31514 (June 3, 2010). The Tailoring Rule limits the applicability of PSD permitting for GHGs to only the highest-emitting GHG sources; in the absence of the Tailoring Rule, the PSD program's existing 100/250 ton-per-year (tpy) thresholds would have applied.

The first step of the Tailoring Rule, which takes effect on January 2, 2011, provides that: (i) PSD or title V requirements will apply to stationary sources' GHG emissions only if the sources are subject to PSD or title V anyway due to their emissions of non-GHG pollutants; (ii) applicable PSD requirements – perhaps most notably of which is the Best Available Control Technology (BACT) requirement – will apply to projects that increase net GHG emissions by at least 75,000 tpy carbon dioxide equivalent ($CO_2$e), but only if the project also significantly increases emissions of at least one non-GHG pollutant; and (iii) for the title V program, only existing sources with, or new sources obtaining, title V permits for non-GHG pollutants will be required to address GHGs.

The second step of the Tailoring Rule, which takes effect on July 1, 2011, phases in additional requirements on stationary sources that emit GHGs. On that date, new sources as well as existing sources not already subject to title V that emit, or have the potential to emit, at least 100,000 tpy $CO_2$e will become subject to the PSD and title V requirements. In addition, sources that emit or have the potential to emit at least 100,000 tpy $CO_2$e and that undertake a modification that increases net emissions of GHGs by at least 75,000 tpy $CO_2$e will also be subject to PSD requirements.

EPA has stated that it will issue a supplemental notice of proposed rulemaking in 2011 in which it will propose comment on a third step of the Tailoring Rule that, effective July 1, 2013, would include more stationary sources in PSD and title V based upon their GHG emissions; EPA intends to finalize this "step 3" rule by July 1, 2012.

As required by the CAA, all States, including California, are currently taking steps to modify their applicable air regulations and CAA State Implementation Plans (SIP) to satisfy these new federal requirements. On September 2, 2010, EPA proposed a "SIP Call" that provisionally found that the applicable SIPs for thirteen States, including California (Sacramento Metropolitan AQMD), lacked adequate provisions to apply PSD requirements to GHG-emitting sources; EPA intends to finalize this action by on or about December 1, 2010. 75 Fed. Reg. 53892 (Sept. 2, 2010). Also on September 2, 2010, EPA proposed a Federal Implementation Plan (FIP) that would apply in any State (including California: Sacramento Metropolitan AQMD) that was unable to submit, by the applicable deadline, a SIP revision to remedy the defects that were identified in the SIP Call. 75 Fed. Reg. 53883 (Sept. 2, 2010).

EPA separately is poised to provide the States with non-binding guidance regarding how to apply applicable PSD and title V requirements to stationary sources effective January 2, 2011. To that end, on September 17, 2010, EPA sent to the White House's Office of Information and Regulatory Affairs (OIRA) a guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases." That document, which remains under review at OIRA but which could be issued imminently, is expected to provide guidance on topics such as what constitutes BACT for GHGs.

One issued to be addressed by EPA going forward is whether, and to what extent, CCS is deemed BACT in the future. BACT is applied on a case-by-case; takes into account energy, environmental, and economic impacts and other costs; and must be "achievable" for the facility. 42 U.S.C. § 7479(3). EPA's 1990 Draft NSR Workshop Manual, which despite its draft status represents longstanding EPA policy and is used in BACT determinations to this day, states that "if the technology has been installed and operated successfully on the type of source under review, then it is demonstrated, and it is technically feasible." Draft NSR Workshop Manual, p. B.17 (EPA 1990). "Demonstrated in practice" generally means that an available process or control technology has been used in a production situation, and has been demonstrated to be successfully at achieving the claimed performance. Bench scale and pilot plant trials alone are generally not sufficient, but may supplement other experience. EPA's Clean Air Act Advisory Committee, during deliberations throughout 2010, declined to take a position on whether CCS might be BACT in specific situations.

From the source perspective, EPA has taken the following additional actions with respect to CCS. On October 30, 2009, EPA published its final rule requiring the mandatory reporting of GHGs (MRR). 74 Fed. Reg. 56260 (Oct. 30, 2009). The MRR applies to "Suppliers of Carbon Dioxide," which includes, in part: (i) facilities with production process units that capture and supply $CO_2$ for commercial applications or that capture and maintain custody of a $CO_2$ stream in order to sequester or otherwise inject it underground; and (ii) facilities with $CO_2$ production wells that extract a $CO_2$ stream for the purpose of supplying $CO_2$ for commercial applications.

On April 12, 2010, EPA proposed an expansion of the MRR to include facilities that inject and store $CO_2$ for the purposes of geologic sequestration or enhanced oil and gas recovery. 75 Fed. Reg. 18576 (April 12, 2010). A key feature of this proposal is the use of "monitoring, reporting and verification" plans for geologic storage sites. EPA transmitted the final version of this rule to OIRA on August 6, 2010, which means that its publication should be imminent.[41]

[41] Similarly, and although not a federal requirement or program per se, the Pew Center on Global Climate Change (Pew) announced on September 30, 2010 that it was developing a framework to quantify GHG reductions from CCS. In its announcement, Pew stated that the "framework will have broad applicability and could support federal and state policy makers in developing meaningful plans to cut GHG emissions over time." http://www.pewclimate.org/press-center/press-releases/pew-center-global-climate-change-developing-framework-quantify-ghg-reduc.

By the end of 2010, EPA is expected to propose a regulation that would clarify how the Resource Conservation and Recovery Act (RCRA) (42 U.S.C. § 9601 et seq.) applies to "$CO_2$ streams" in the CCS context. EPA is considering a proposed rule under RCRA "to explore a number of options, including a conditional exemption from the RCRA requirements for hazardous CO2 streams in order to facilitate implementation of geologic sequestration, while protecting human health and the environment."[42]

EPA continues to evaluate how to implement the Intergovernmental Panel on Climate Change's (IPCC) 2006 guidelines regarding accurately accounting for emissions associated with transport, injection and storage of $CO_2$.[43]

### Pipelines

States such as California, as opposed to the federal government, have primary authority over carbon dioxide pipelines. With respect to siting and eminent domain, there is no current federal regulatory scheme for $CO_2$ pipelines.[44] The Bureau of Land Management (BLM) has imposed the equivalent of a common carrier obligation on $CO_2$ pipelines crossing federal lands on the basis that $CO_2$ is a "natural gas."

With respect to safety regulation, the U.S. Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) has primary authority to regulate interstate $CO_2$ pipelines under the Hazardous Liquid Pipeline Act of 1979. PHMSA's Office of Pipeline Safety regulates the design, construction, operation, maintenance, and spill response planning for regulated pipelines. PHMSA establishes minimum safety standards for interstate pipelines, and has largely preempted States from establishing their own standards for interstate pipelines.
DOT's pipeline regulations specifically exclude small segments of $CO_2$ pipelines that are used in $CO_2$-EOR operations. Excluded from regulation, for example, is the transportation of CO2 "downstream" of the following points: (i) the inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, which is farther upstream; or (ii) the connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well. 49 C.F.R. § 195.1.
In the fall of 2010, DOT transmitted to Congress legislation that would broadly amend the federal scheme for interstate pipeline safety regulation. That legislation included provisions that would expand PHMSA authority over $CO_2$ pipelines to include interstate pipelines carrying $CO_2$ in a "gaseous" state.

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### Geologic Injection and Storage

#### *Hazard Classification of $CO_2$ Injectate Under Federal Law*

Perhaps of greatest relevance for geologic sequestration and for purposes of the pending Safe Drinking Water Act (SDWA) (42 U.S.C. §§ 300f to 300j-26) sequestration regulations (discussed separately below), EPA has referenced the $CO_2$ injectate with respect to the term "carbon dioxide stream," which means: "carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from source materials and the capture process, and any substances added to the stream to enable or improve the injection process." 73 Fed. Reg. 43492, 43535 (July 25, 2008).

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[42] See http://yosemite.epa.gov/opei/RuleGate.nsf/byRIN/2050-AG60.
[43] See http://www.epa.gov/climatechange/emissions/co2_gs_inventory.html.

[44] See R. Nordhaus, "Carbon Dioxide Pipeline Regulation" (available at http://www.vnf.com/assets/attachments/RRNERP.Carbon_Dioxide_Pipeline_Regulation.Energy_Law_Journal.Volume_30.Number1.2009.pdf).

According to EPA, carbon dioxide is not a hazardous substance under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund) (42 U.S.C. §§ 9601 to 9675).[45] Thus, geologic sequestration of $CO_2$, in and of itself, should not give rise to CERCLA liability. Sequestration of $CO_2$ could give rise to CERCLA liability, however, if the $CO_2$ stream contained constituents that are CERCLA hazardous substances from the source materials or the capture process or if the $CO_2$ stream reacted with groundwater to produce a CERCLA hazardous substance. Similarly, it does not appear that EPA has listed any $CO_2$ streams as a "listed" RCRA hazardous waste. Thus, for RCRA hazardous waste jurisdiction to attach to a $CO_2$ stream, it would have to be "characteristically" hazardous – *i.e.*, meet one or more objective criteria set out at 40 C.F.R. §§ 261.20-261.24 for toxicity, corrosivity (*i.e.*, pH), ignitability, reactivity.

Also of relevance for geologic sequestration, $CO_2$, when transported via pipeline, is not deemed to be hazardous. The applicable regulations apply to pipeline facilities "used in the transportation of hazardous liquids <u>or</u> carbon dioxide." 49 C.F.R. § 195.0 (emphasis added). They define "carbon dioxide" to mean "a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state." Id. § 195.2.

Of less relevance for commercial geologic sequestration operations perhaps but nonetheless informative:

(1) The CAA regulations described above apply to "air pollutants," not $CO_2$ when it is injected for purposes of geologic sequestration. EPA has defined as the basket of six primary GHGs, not $CO_2$ alone; and
(2) When transported by ground, rail, inland waterway, or rail, carbon dioxide in specific forms (e.g., as a refrigerated liquid or as solid or dry ice) appears on DOT's table of hazardous materials (Hazmat). 49 C.F.R. § 172.101. The gaseous and refrigerated liquid forms of CO2 specifically are classified as Class 2.2 (non flammable gases) for Hazmat purposes.[46]

*<u>Injection Well Regulation</u>*

EPA is poised to issue final injection well regulations under the SDWA that would apply to sequestration wells. The final regulations, which EPA proposed on July 25, 2008 (73 Fed. Reg. 43492 (July 25, 2008), were transmitted to OIRA on August 6, 2010, which means that their publication should be imminent.

Based upon the proposed rule, the final regulations are expected to apply to owners and operators of wells that inject $CO_2$ into the subsurface for purposes of long-term storage. They will likely include a new well classification – to be called Class VI – and minimum technical criteria for the geologic site characterization, fluid movement, area of review and corrective action, well construction, operation, mechanical integrity testing, monitoring, well plugging, post-injection site care, and site closure for the purposes of protecting underground sources of drinking water (USDW). The final regulations will be based upon the SDWA's existing UIC regulatory framework. EPA has stated that the regulations "would help ensure consistency in permitting underground injection of $CO_2$ at [geologic sequestration] operations across the U.S. and provide requirements to prevent endangerment of USDWs in anticipation of the eventual use of [geologic sequestration] to reduce $CO_2$ emissions.

[45] 73 Fed. Reg. 43,492, 43,504 (July 25, 2008).

[46] DOT's pipeline regulations similarly exclude from regulation the transportation of $CO_2$ by "vessel, aircraft, tank truck, tank car, or other non-pipeline mode of transportation." 49 C.F.R. § 195.1.

It is unclear if the final regulations will allow States such as California to have primacy enforcement authority over the new Class VI wells. Section 1422 of the SDWA provides that the States may apply to EPA for primary enforcement responsibility to administer the UIC program; governments receiving such authority are referred to as "primacy States." Section 1422 requires the primacy States to meet the UIC's program minimum federal requirements, including construction, operating, monitoring and testing, reporting, and closure requirements for well owners and operators. Where States do not seek this responsibility or fail to demonstrate that they meet EPA's minimum requirements, EPA to required to implement a UIC program for them. Additionally, section 1425 of the SWDA allows the States seeking primacy for Class II wells – which, for present purposes, are those wells used to inject carbon dioxide for purposes of enhanced oil recovery ($CO_2$-EOR) – to demonstrate that their existing standards are effective in preventing endangerment of USDWs. EPA has taken comment on how these provisions might apply to the new Class VI wells. 73 Fed. Reg. at 43523. This development could specifically impact California, which only has primacy for Class II wells (to the California Division of Oil, Gas, & Geothermal Resources), because EPA seems to be questioning whether a "piecemeal" delegation of Class VI would be permissible, or instead if Class VI could only be delegated to those States (not including California) that have been delegated responsibility for all well classes under the UIC program.

On March 1, 2007, EPA issued guidance to the States regarding how to permit pilot geologic sequestration projects under UIC Class V, which applies to experimental technology wells.[47]

*Long Term Stewardship*

There is no federal program for the long-term stewardship of geologic storage sites during the site's "post-closure phase,"[48] which is also sometimes referred to as the "stewardship period."

Federal legislation to accomplish that end has been introduced. Introduced on July 14, 2010, S. 2589, the "Carbon Capture and Sequestration Deployment Act of 2010," would: (i) provide for long-term stewardship of closed carbon dioxide storage sites to ensure continuing protection of health, safety, and the environment during the stewardship period; (ii) provide a system for compensation to any person that may suffer personal injury or property damage from storage carbon dioxide at such a site; (iii) establish financial responsibility and a dedicated funding mechanism in the form of a trust fund for such stewardship and compensation; and (iv) establish a transitional program that provides limited indemnification for owners and operators of qualifying first mover projects to demonstrate the capture and geologic storage of carbon dioxide.[49] S. 2589 remains pending before the Senate Committee on Energy & Natural Resources.

On June 17, 2009, the Senate Committee on Energy & Natural Resources marked up, S. 1462, the American Clean Energy Leadership Act (ACELA). S. 1462 would establish a national indemnity program through the U.S. Department of Energy (DOE) for up to ten commercial-scale capture and sequestration projects. S. 1462 remains pending in the Senate.

**Financial Support**

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[47] See March 1, 2007 Memorandum from Cynthia Dougherty regarding "Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UICPG #83) (available at http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf).

[48] The U.S. Department of Energy, consistent with the laws of several States, considers the "post-closure phase" to mean the period after the site has been closed and "during which ongoing monitoring is used to demonstrate that the storage project is performing as expected until it is safe to discontinue further monitoring." http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html.

[49] See S. 3589.

The federal government has provided, and continues to provide, a variety of funding assistance to qualifying CCS projects.

*Tax-Related Incentives*

*Section 45Q Sequestration Credit*

The Energy Improvement and Extension Act of 2008 ("EIEA") – enacted last fall as part of the Emergency Economic Stabilization Act of 2008 – added a new section 45Q sequestration tax credit. Section 45Q has two parts. The first part is a credit of $20 per metric ton for "qualified carbon dioxide" captured by a taxpayer at a qualified facility and disposed of by such taxpayer in secure geological storage (including storage at deep saline formations and unminable coal seams under such conditions as the Secretary of the Treasury may determine).

The second part allows a credit of $10 per metric ton of qualified carbon dioxide that is captured by the taxpayer at a qualified facility and used by such taxpayer as a tertiary injectant (including carbon dioxide augmented waterflooding and immiscible carbon dioxide displacement) in a qualified enhanced oil or natural gas recovery project. In early 2009, as part of the American Recovery and Reinvestment Act (ARRA), this provision was amended to require that the qualified carbon dioxide end up in "secure geological storage."

"Qualified carbon dioxide" is defined as carbon dioxide captured from an industrial source that (1) would otherwise be released into the atmosphere as an industrial emission of greenhouse gas, and (2) is measured at the source of capture and verified at the point or points of injection. Qualified carbon dioxide includes the initial deposit of captured carbon dioxide used as a tertiary injectant but does not include carbon dioxide that is recaptured, recycled, and re-injected as part of an enhanced oil or natural gas recovery project process.

A "qualified facility" means any industrial facility (1) which is owned by the taxpayer, (2) at which carbon capture equipment is placed in service, and (3) which captures not less than 500,000 metric tons of carbon dioxide during the taxable year. The credit applies only with respect to qualified carbon dioxide captured and sequestered or injected in the United States or one of its possessions. Except as provided in regulations, credits are attributable to the person that captures and physically or contractually ensures the disposal, or use as a tertiary injectant, of the qualified carbon dioxide. Credits are subject to recapture, as provided by regulation, with respect to any qualified carbon dioxide that ceases to be recaptured, disposed of, or used as a tertiary injectant in a manner consistent with the rules of the provision.
The credit is part of the general business credit. The credit sunsets at the end of the calendar year in which the Treasury Department, in consultation with EPA, certifies that 75 million metric tons of qualified carbon dioxide have been captured and disposed of or used as a tertiary injectant.

In late 2009, the U.S. Internal Revenue Service issued a notice regarding its interpretation of the section 45Q credit.[50]

Federal legislation recently has been recently to amend the section 45Q credit. S. 3935, the "Advanced Energy Tax Incentives Act of 2010," would provide the following changes to section 45Q: (i) increase the 75 million metric ton cap to 100 million metric tons; (ii) please a 10 million metric ton credit cap on any one project; (iii) increase the $20 ton credit amount to $35; (iv) toughen the definition of "qualified facility" to include a requirement that the taxpayer show "contractual intent to inject and permanently sequester the full amount of captured carbon dioxide"; and (v) add new

[50] http://www.irs.gov/irb/2009-44_IRB/ar11.html.

provisions to allow credit certification in advance, with a look-forward period of 10 years, measured from the date when the taxpayer has received its permits under the CAA. S. 3935 remains pending the Senate.

*Section 48A Qualifying Advanced Coal Project Credit*

The section 48A qualifying advanced coal project credit was originally enacted as part of the Energy Policy Act of 2005 (EPAct).[51]

Section 48A provides for a 20% investment tax credit on qualified investments in IGCC projects and a 15% investment tax credit on qualified investments in other advanced coal-based generation technologies. Taxpayers must apply for an allocation of the credits from the Treasury Department during a designated application period, with aggregate credits to be awarded capped at $800M for integrated gasification combined cycle (IGCC) projects and $500M for other advanced coal-based generation projects. The requirements for an allocation of credits include (1) that the project uses advanced coal-based technology to power an electrical generation unit, (2) the fuel input upon completion must be at least 75% coal, (3) the nameplate capacity must be at least 400 MW, and (4) the project must be located in the United States.

For the IGCC portion of the credit, priority is given to those projects that have a "greenhouse gas capture capability," defined as "an integrated gasification combined cycle technology facility capable of adding components which can capture, separate on a long-term basis, isolate, remove, and sequester greenhouse gases which result from the generation of electricity."[52]

EIEA added a second application period, with an additional $1.250B of tax credits which may be awarded to such projects during that period. The credit is increased to 30% for these second-round projects and a requirement is added that projects must sequester at least 65% of their carbon dioxide emissions. Priority for awarding credits is given to those projects with the greatest percentage of carbon dioxide separation and sequestration.

*Section 48B Qualifying Gasification Project Program*

The section 48B qualifying advanced gasification project program was originally enacted as part of EPAct.

Section 48B provides for a 20% investment tax credit on qualified investments in qualifying gasification projects. Such credits are subject to an application process similar to the Section 48A credits, as discussed above, with an aggregate cap of $350M on credits which can be awarded.

The aggregate credit is allocated first to the projects that have "carbon capture capability," defined as a "gasification plant design which is determined by the Secretary [of the Treasury] to reflect reasonable consideration for, and be capable of, accommodating the equipment likely to be necessary to capture carbon dioxide from the gaseous stream, for later us or sequestration, which would otherwise be emitted in the flue gas from a project which uses a nonrenewable fuel."[53]

EIEA added a second allocation cap of $250M for projects in which a minimum of 75% of carbon dioxide emissions are separated and sequestered. The credit percentage for such projects is increased to 30%. Priority for awarding credits is given to those projects with the greatest percentage of carbon dioxide separation and sequestration.

*<u>Funding/Stimulus Programs</u>*

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[51] See http://www.irs.gov/pub/irs-drop/n-06-24.pdf.

[52] <u>See</u> § 48A(c)(5).

[53] <u>See</u> § 48B(c)(5).

For many years, DOE's Office of Fossil has managed and funded a variety of programs and initiatives to advance CCS, including, but not limited to, WESTCARB 00 the West Coast Regional Carbon Sequestration Partnership.[54]

These programs and initiatives, in whole or in part, were given a boost in early 2009 with the enactment of ARRA, which allocated $3.4 billion to DOE for CCS-related grants and related expenditures, including: (i) Clean Coal Power Initiative Round III[55]; (ii) industrial CCS; (iii) site characterization activities in geologic formations; (iv) geologic sequestration training and research; and (v) direct program funding. During 2009 and 2010, DOE issued a series of funding announcements under these and related programs; award recipients have been announced in many instances.[56]

*Federal Loan Guarantees*

DOE's Loan Guarantee Program (LGP) was established under EPAct and was designed to support eligible projects that avoid, reduce or sequester air pollutants, including anthropogenic emissions of GHGs using new and innovative technology. DOE issued a final rule governing the LGP on October 23, 2007; under that rule: (i) applicants must pay administrative costs and the credit subsidy cost of their proposed project; (ii) the loan guarantee must not cover more than 80% of the total project cost; (iii) the loan guarantee must not finance tax-exempt debt obligations; (iv) project sponsors must make a significant equity contribution to the project; and (v) DOE must hold the first lien on all project assets pledged as collateral for the loan.

*Eligible CCS projects fall under what is known as Section 1703 of the LGP.*[57]

On a related front, the Food & Energy Security Act of 2007 directed the U.S. Secretary of Agriculture to conduct a study on electric power generation needs in rural areas of the United States, including issues associated with CCS.[58] On January 15, 2009, under the Rural Development Electric Program, the Secretary of Agriculture announced the approval of a $300M loan to finance the modification of Basin Electric Power Cooperative's Antelope Power Station near Beulah, North Dakota. The program involves the installation of carbon capture technology, with the bulk of the captured $CO_2$ destined for the pipeline which currently carries $CO_2$ from the Great Plains Synfuel Plant to EOR fields to the north.

*FutureGen 2.0*

On August 5, 2010, U.S. Secretary of Energy Steven Chu announced the awarding of $1 billion in ARRA funding for a reconstituted FutureGen program, now called FutureGen 2.0.[59]

*Geologic Sequestration on Public Lands*

[54] These programs and initiatives are outlined here: http://www.fossil.energy.gov/programs/sequestration/index.html.

[55] DOE's goals in Round 3 are to cost share to demonstrate at commercial scale in a commercial setting technologies that: (1) operate at 90% carbon dioxide capture efficiency; (2) make progress toward capture and sequestration at less than 10% increase in the cost of electricity for gasification systems and less than 35% for combustion and oxy combustion systems; and (3) make progress toward capture and sequestration of 50% of plant $CO_2$ output at a scale sufficient to evaluate impact of the carbon capture technology on plant operations, economics, and performance. At least 300,000 tons per year of carbon dioxide emissions from the demonstration plant must be captured and sequestered or put to beneficial reuse. The carbon capture process must operate at a capture efficiency of at least 90%.

[56] More details are available here: http://www.energy.gov/recovery/ccs.htm.

[57] More details about section 1703 of the LGP are available here: http://lpo.energy.gov/?page_id=39.

[58] See http://www.rurdev.usda.gov/rd/farmbill/08/GenInfo/ElectricPowerGenerationReport.pdf and

[59] More details are available here: http://www.energy.gov/news/9309.htm.

The federal government is actively pursuing the establishment of a regulatory framework for conducting geologic sequestration on public lands. Pursuant to section 714 of the Energy Independence and Security Act of 2007, the U.S. Department of Energy issued a report in 2009 on a regulatory framework for geological sequestration on public lands.[60] DOE issued a similar report the same year.[61]

These efforts include the consideration of federal legislation, such as S. 1856, that would clarify the ownership of pore space beneath federal lands. S. 1856 remains pending in the Senate.

*White House Task Force Report*

On August 12, 2010, the White House's Interagency Task Force on CCS (Task Force) delivered its report to the President of the United States. Co-chaired by EPA and DOE, the Task Force was tasked with proposing a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within 10 years, with a goal of bringing 5 to 10 commercial demonstration plants online by 2016. The report reflects input from 14 federal agencies and departments as well has hundreds of stakeholders and CCS experts.Federal Cap-and-Trade Legislative Proposals.

All of the major cap-and-trade proposals considered by the 111th Congress, such as H.R. 2454 (the so-called Waxman-Markey bill that passed the House of Representatives in 2009) and S. 1733 (the so-called Kerry-Boxer bill that passed the Senate Committee on Environment and Public Works in 2009) recognized "carbon capture" as a non-emitting event and generally provided CCS with various subsidies, including bonus allowances, in recognition of the economic hurdles facing the technology in the early years of its deployment.

**Brief Overview of Policy Developments in Other States**

A summary of state-level policies regarding geological sequestration (GS) of $CO_2$ was presented to the Panel in April 2010 testimony by Dr. Sean McCoy, director of the CCSReg Project at Carnegie Mellon University, and updated in a subsequent presentation by M. Pollak at the national CCS conference in May 2010. This overview is drawn primarily from these CCSReg Project materials.

As of May 2010, twenty U.S. states have enacted some type of policy regarding geological sequestration (see Figure 1). These range from legislation and regulations to address specific aspects of GS operations (ten states), to support only for incentives or studies (ten states).

[60] "Report to Congress: Framework for Geological Carbon Sequestration on Public Land" (DOI 2009).
[61] "Storage of Captured Carbon Dioxide Beneath Federal Lands" (DOE 2009).

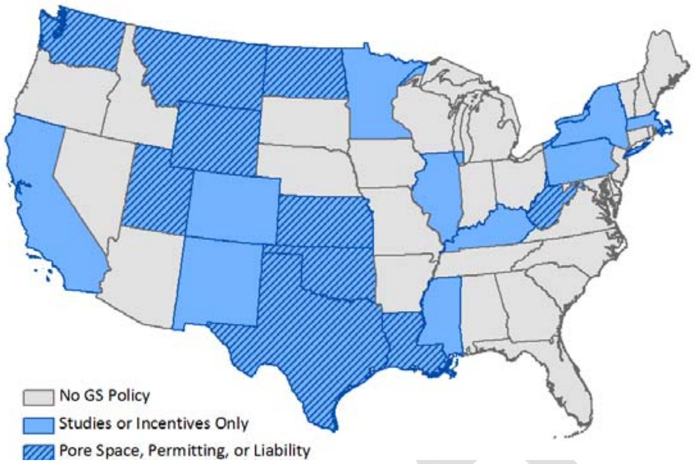


**Figure 1. Status of state-level policies for geological sequestration. (Source: Pollack, et al. 2010)**

Of particular interest are state policies addressing three major aspects of a CCS project:

- Access to pore space for sequestering $CO_2$
- Permitting of geological storage sites
- Managing long-term liabilities

*Access to Pore Space*

Three states (Montana, North Dakota and Wyoming) have established that pore space is a property right tied to the surface estate. These states also have compulsory unitization (adapted from oil-field development policies), meaning that once a specified percentage of landowners (ranging from 60% to 80%) have voluntarily committed to allow their pore space to be developed and used as a single sequestration unit, the remaining landowners may be compelled by law to join the unit. Four other states, however, have declared that geologic sequestration is in the public interest, a prerequisite for use of eminent domain. To date, only Louisiana has established a process that would allow developers to obtain a certificate of public convenience and necessity to exercise the power of eminent domain.

*Permitting GS Sites*

With regard to permitting of geological storage sites, states are choosing to delegate authority to different types of state agencies. In some cases responsibility is vested with the regulator of oil and gas operations, while in other cases the responsibility lies with the state environmental agency, or is shared between two agencies.

Another distinction is the statutory authority under which GS permits are granted. Two different models are emerging (Pollak, et al. 2010). One is state implementation of the Underground Injection Control (UIC) program under authority of the federal Safe Drinking Water Act and the state's analog. This is the model adopted by Washington and Wyoming. Here, permits are granted for individual wells with a risk management focus on preventing impacts to underground sources of drinking water (USDWs).

An alternative model, adopted by Kansas and North Dakota, involves new freestanding GS legislation. Here, permits are granted to GS facilities or projects, rather than individual wells. In principle, the risk management scope in this approach can be broadened to include all potential impacts, not solely USDWs.

State permitting requirements also include some type of financial assurance mechanism such as a bond, insurance, or other type of financial assurance to ensure the proper operation and closure of GS site (Table 1). This requirement may or may not explicitly include assurances for the post-closure period. As discussed below, however, some states have also created a state fund (e.g., based on a fee per ton of $CO_2$ injected, as in Kansas and North Dakota) to cover certain post-closure costs, should they arise. *[NOTE: need to check this.]*

**Table 1. Financial assurance requirements for a GS site (Source: McCoy, et al., 2010)**

| State | Financial Assurance Requirements |
|---|---|
| Kansas | • Demonstration of financial responsibility to ensure proper operation and closure of the $CO_2$ storage facility, as approved by the Director. |
| North Dakota | • Performance bond covering surface facility in an amount established by the Commission.<br>• Performance bonds for each $CO_2$ injection and observation well in amount established by the Commission. |
| Washington | • Operator shall establish a closure and post-closure account to cover all closure and post-closure expenses. |
| Wyoming | • Public Liability Insurance policy (or self insurance) for GS operations.<br>• Bond or other financial assurance to the cover cost of meeting permit requirements, including monitoring, remediation and site closure. |

*Managing Long-term Liabilities*

"Long-term liabilities" refers to liabilities that may occur in the "stewardship" period following the authorized closure of a GS site. State policies for managing such liabilities differ first in the criteria or requirements for site closure, as illustrated in Table 2.

**Table 2. State requirements for closure of a GS site (Source: McCoy, et al. 2010)**

| State | Requirements for Closure | Consequences of Closure |
|---|---|---|
| Kansas | • $CO_2$ plume is stabilized, contained, an not a threat to public health, safety and usable water<br>• $CO_2$ reservoir pressure is stable | • $CO_2$ storage facility permit is revoked<br>• Monitoring and remediation paid for by state trust fund |
| North Dakota | • Show position and characteristics of injected $CO_2$<br>• Reservoir is reasonably expected to retain mechanical integrity | • Bond is released<br>• Monitoring and remediation become responsibility of designated state or federal agency |
| Washington | • Little or no risk of future environmental impacts and high confidence in effectiveness of the containment system | • Funds remaining in financial assurance account are released |

| | | |
|---|---|---|
| Wyoming | • > 10 years after injection stops<br>• 3 years of monitoring data showing plume has stabilized<br>• $CO_2$ will not present a risk to human health, safety or the environment | • All financial assurance instruments are released<br>• Monitoring and remediation paid for by state trust fund |

As noted earlier, some states have adopted a funding mechanism for long-term stewardship during the post-closure period. Approved uses for state long-term GS funds are limited to only certain types of liabilities. The six states that have addressed long-term stewardship are handling different types of liability quite differently (Table 3). No state explicitly approves the use of state long-term GS funds to cover tort liabilities or climate liabilities (e.g., an obligation to submit allowances or to take other actions to compensate for leakage of $CO_2$ to the atmosphere under a greenhouse gas emission reduction program) (Pollak, et al. 2010). However, the statutory language in the Montana and North Dakota bills is so broad as to imply such coverage. For example, Montana SB 498 says the state will assume "All rights and interests in, and all responsibilities associated with, the geologic storage reservoir and the stored carbon dioxide."

**Table 3. Approved uses for state long-term GS funds (Source: Pollak, et al. 2010)**

| State | Long-term Site Management | | | Tort Liability | Climate Liability |
|---|---|---|---|---|---|
| | Monitor | Remediate: Limited | Remediate: Full | | |
| Montana SB 498 (2009) | ✓ | | ✓ | ✓ | ✓ |
| North Dakota SB 2095 (2009) | ✓ | | ✓ | ✓ | ✓ |
| Kansas HB 2419 (2007) | ✓ | | ✓ | | |
| Louisiana HB 661 (2009) | ✓ | ✓ | | | |
| Texas SB 1387 (2009) | ✓ | ✓ | | | |
| Wyoming HB 17 (2010) | ✓ | | | | |

As seen in Table 3, most states limit their long-term liability to selected aspects of GS site management. Louisana and Texas, for example, limit the remediation the state would perform to the repair of mechanical leaks, while Wyoming would use the state fund only for monitoring, not remediation. There is no clear answer yet as to who would be responsible for the long-term liabilities that states are unwilling to assume.

*Treatment of Enhanced Oil Recovery (EOR)*

With only one exception, all states that have adopted GS policies addressing pore space, permitting, and/or liability have exempted enhanced oil recovery (EOR) operations from that legislation (Pollak, et al. 2010). The key motivation has been to protect EOR business interests in the state. In general, the objectives and expectations of a GS project (with respect to such issues as site characterization, well construction and monitoring) are different and typically more stringent than for EOR. Thus, the application of GS requirements to EOR operations that inject $CO_2$ could potentially harm the EOR business. The explicit exemption of $CO_2$-EOR operations conducted under the UIC Class II program is thus a noteworthy provision of state GS policies.

Several states also are beginning the process of setting rules that would allow EOR projects to be converted GS sites and obtain carbon credits under a future policy limiting GHG emissions (Table 4). These rules are not yet in place, but are expected to develop over the next few years (Pollak, et al. 2010).

**Table 4. State policies for GS via enhanced oil recovery (EOR) (Source: Pollak, et al. 2010)**

| State | Bill(s) | EOR Exempt from GS Regs | Conversion to GS Site* | Carbon Credits for EOR-GS* |
|---|---|---|---|---|
| Kansas | HB 2419 (2007) | ✓ | | |
| Louisiana | HB 661 (2009) HB 1117 (2008) | ✓ | | |
| Montana | SB 498 (2009) | ✓ | ✓ | |
| North Dakota | SB 2095 (2009) SB 2034 (2009) | ✓ | ✓ | ✓ |
| Oklahoma | SB 610 (2009) | ✓ | | |
| Texas | SB 1387 (2009) | ✓ | ✓ | |
| Utah | SB 202 (2008) | ✓ | | |
| West Virginia | HB 2860 (2009) | ✓ | | ✓ |
| Wyoming | HB 90 (2009) | ✓ | ✓ | |

* Rules under development

*Summary and Conclusion*

Table 5 gives a more detailed summary of the state policies discussed above. While California is unique in having a state-level policy limiting emissions of greenhouse gases, aspects of other state policies regarding GS can serve as useful models in shaping a policy that best fits the circumstances and needs of California.

**Table 5. Summary of state geologic storage policies as of May 1, 2010 (Source: Pollak, et al. 2010)**

| State | Property Rights, incl. Access to Pore Space | Permitting Rules | Long-term Stewardship |
|---|---|---|---|
| **Kansas**<br>2009: KAR 82-3-1100-1120<br>2007: HB 2719 | N/A | Agency: KS Corporation Commission. Rules adopted Feb. 2010 | State will assume long-term site management, but limited liability.<br>Fund established for long-term monitoring and remediation. |
| **Louisiana**<br>2009: HB 661<br>2008: HB 1220, 1117 | Addresses $CO_2$ ownership, liability during operations, and eminent domain. Does not address pore space ownership. | Agency: Office of Conservation, Dept. of Nat. Resources. Rules not yet proposed. | State will assume long-term ownership but limited liability.<br>Fund established for long-term monitoring and limited remediation. |
| **Montana**<br>2009: SB 498 | Addresses pore space ownership, liability during operations, mineral rights primacy, $CO_2$ ownership, and provides for unitization. | Agency: MT Board of Oil and Gas Conservation, with comments from MT Board of Env. Review. Rules not yet proposed. | State will assume long-term ownership and liability.<br>Fund established for all long-term liabilities. |
| **North Dakota**<br>2009: SB 2095, SB 2139 | Addresses pore space ownership, $CO_2$ ownership, liability during operations, mineral rights primacy, and provides for unitization. | Agency: ND Industrial Commission. Rules adopted November 2009 | State will assume long-term ownership and liability.<br>Fund established for all long-term liabilities. |
| **Oklahoma**<br>2009: SB 610<br>2008: SB 1765 | Addresses $CO_2$ status and ownership and mineral rights primacy. Inventory accounting rules adopted. Does not adress pore space ownership and liability during operations. | Agency: Corporation Commission for fossil fuel-bearing formations; Dept. of Env. Qual. for all others.<br>Rules not yet proposed. | N/A |

| State | Property Rights, incl. Access to Pore Space | Permitting Rules | Long-term Stewardship |
|---|---|---|---|
| **Texas**<br>2009: HB 1387, HB1796 | Addresses $CO_2$ ownership, liability during operations. Does not address pore space ownership. | Agency: Railroad Commission, Texas Commission on Env. Quality. Draft rules issued March 26, 2010 | State will assume limited long-term site management but not all liabilities. Fund established for long-term monitoring and limited remediation. |
| **Utah**<br>2008: SB 202 | N/A | Agency: Dept. Of Env. Quality. Rules not yet proposed. | N/A |
| **Washington**<br>2008: WAC 173-407-110<br>2007: **ESSB 6001** | N/A | Agency: Department of Ecology<br>Rules adopted in 2008. | N/A |
| **West Virginia**<br>2009: HB 2860, W.V. Code, Chap. 22, Art. 11A | Addresses mineral rights primacy. Assigns study group to make recommendations on other issues such as pore space ownership by 2011. | Agency: Dept. of Env. Protection Rules not yet proposed. | N/A |
| **Wyoming**<br>2010: HB 17<br>2009: HB 57, 58, 80, Water Qual. Rules & Regs. Chap. 24**<br>2008: HB 89, 90 | Addresses pore space ownership, $CO_2$ ownership, liability during operations, mineral rights primacy, and provides for unitization. | Agency: Dept. of Env. Quality. Draft rules published 3/13/09, rev. 9/25/09 | State will assume limited long-term site management but not all liabilities. Fund established for long-term monitoring. |

N/A – Not Addressed **Proposed Rules

***References***


McCoy, S.T., M. Pollak and R.L. Gresham, “State Legislative and Regulatory Actions: Review, Motivation, and Effects on Geologic Sequestration of Carbon Dioxide,” Presentation to the California Carbon Capture and Storage Review Panel Meeting, Sacramento, CA, April 22, 2010.

Pollak, M., R.L. Gresham, S.T. McCoy and S.J. Phillips, “State Regulation of Geologic Sequestration: 2010 Update,” Proceedings of Ninth Annual Conference on Carbon Capture & Sequestration, Pittsburgh, PA, May 10 -13, 2010.

## IV. Issues Requiring Attention and Resolution to Enable Safe and Effective CCS Demonstrations & Commercial Deployment in California

### IV.1. ***The Regulatory Framework for CCS Projects*** [

*IV.1.a. What constitutes "The Project"?*

*IV.1.a.(i) Treatment of "Capture" Under Current CA Law*

*IV.1.a.(ii) Regulation of Pipelines Under Current CA Law*

**Fire Marshall**

*IV.1.a.(iii) Regulation of Geologic Injection Under Current CA Law*

**DOGGR (Class II EOR Only)**

**Class V R&D (EPA Region 9)**

**Class VI (will depend on forthcoming rule)**

*IV.1.a.(iv). Regulation of Geologic Storage Under Current CA Law*

**Not addressed and DOGGR has disclaimed authority/interest**

*IV.1.a.(v). Options for California [pros and cons]*

*IV.1.b. One-Stop Shopping/Unitary Permitting*

*IV.1.b.(i). CPUC Authority Over Utilities and Related Infrastructure*

*IV.1.b.(ii). "Related" understood to mean grid, not pipelines, but presumably could include "all connected" infrastructure*

*IV.1.b.(iii). Other Source Types – Outcome Less Clear*

*IV.1.b.(iv). Options for California [pros and cons]*

### ***IV.2. Regulation and Permitting of $CO_2$ Pipelines***

*IV.2.a. Safety*

*IV.2.b. Siting*

*IV.2.c. Rate regulation*

*IV.2.d. Options for California [pros and cons]*

### ***IV.3. Ownership of Pore Space for $CO_2$ Storage*** (Stoel Rives)

There are no established rules in California that govern ownership or use of subsurface pore space for carbon sequestration. Yet, carbon sequestration cannot occur absent the right to inject and store $CO_2$. Therefore, in order for carbon sequestration to play a role in achieving California's climate goals, ownership of pore space rights needs to be clarified and statutory procedures need to be established for the acquisition of pore space rights. Further statutes can clarify which parties retain ownership of and liability for injected $CO_2$. Uncertainty about these issues creates risks for investors and landowners that will delay or prevent development of carbon sequestration projects in California if they remain unaddressed.

There are three basic approaches to acquiring pore space rights for carbon sequestration that have been discussed in recent years: 1) a traditional private property approach, 2) a limited private property approach, and 3) a public resource approach. Each approach has positives and negatives that would impact the rights of property owners, the rights of early movers in carbon sequestration development, the economics of carbon sequestration projects, and the level of regulatory infrastructure and public resources required.

### *IV.3.a. Traditional Private Property Approach.*

The traditional private property approach recognizes that the right to use the pore space for the injection and sequestration of $CO_2$ is a property right that must be acquired from the property owner in return for payment.[62] If there is a single owner of any property, that owner owns the right to use the subsurface pore space. If the mineral rights have been reserved upon sale of the property, or sold separately from the rest of the property then the owner of the mineral estate has the dominant right to use pore space to the extent necessary to produce valuable minerals.[63] The surface estate owner's use of pore space cannot interfere with the mineral estate. Injecting $CO_2$ into pore space without first acquiring the right to do so could constitute a trespass against both the surface and the mineral estate.[64]

It can be difficult to establish that a mineral estate has been exhausted (*i.e.*, there are no more minerals that can be economically recovered), so if the right to extract minerals is separately owned, a carbon sequestration developer will may need to negotiate with the owners of both the surface estate and the mineral estate. A lease or easement may be obtained from the surface owner for use of the pore space. The mineral owner (and any royalty owners) may be asked to sell rights to the formation in which sequestration will occur, or to acknowledge that the target formation does not contain minerals, and to consent to its use for sequestration. If negotiations are unsuccessful, carbon sequestration developers will need alternative means to acquire pore space rights, such as the power of eminent domain or the right to unitize formations for sequestration, as is often done for oil and gas recovery.

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[62] *See* CAL. CIV. CODE § 829 ("The owner of land in fee has the right to the surface and to everything permanently situated beneath or above it.").

[63] The terms "surface estate" and "mineral estate" are commonly used in the context of severed property rights. However, these terms are misnomers, because the owner of the "surface estate" owns everything, including rights to use the subsurface, except for and subservient to the right to produce valuable minerals. In addition, the owner of the "mineral estate" has certain rights to use the surface in connection with the production of valuable minerals.

[64] *See Cassinos v. Union Oil Co.*, 18 Cal. Rptr. 2d 574 (Cal. App. 1993). Trespass could also result if injected gas causes brine to migrate into the pore space of another property that did not previously contain brine. For example, if displaced brine interfered with oil or gas production or fresh water aquifers, a cause action for trespass could exist under *Cassinos. See also* footnote 66 below and accompanying text.

This traditional property approach closely follows the laws applicable to underground natural gas storage projects in the United States. The Interstate Oil and Gas Compact Commission (the "IOGCC"), comprised of oil and gas regulators from across the country, has recommended that carbon sequestration be treated like natural gas storage. Several states, such as Wyoming, Montana, and North Dakota, have enacted carbon sequestration legislation following this recommendation. Statutes in these states declare that pore space belongs to the surface estate, subject to the use rights of any separate mineral owners. These states also provide eminent domain or unitization authority to acquire pore space if purchase negotiations do not succeed. In all cases, the property owner receives payment for the use of pore space. Further, such statutes generally declare that $CO_2$ injected into pore space is owned by the sequestration operator and the operator, rather than the landowner, remains liable for any damages caused.

**Legislation Needed:** The traditional private property approach would require legislation that:

- allocates ownership of pore space (e.g. to the surface owner or to the mineral rights owner),
- defines ownership and liability for injected $CO_2$, and
- allows for unitization and/or eminent domain to acquire pore space, including pore space owned by state and local governments.

**Positives:**

**a) Payment to property owners may promote acceptance of carbon sequestration by property owners.** Property owners expect that they will be compensated when someone else wants to use their land. This expectation has historical roots beginning with the California's gold rush, the early twentieth century oil and gas boom through today's oil and gas production, natural gas storage, geothermal leases, wind farms and solar development. Oil and gas, geothermal, wind and solar agreements often base payments to landowners on the ongoing revenue of the project, as opposed to one time payments. Landowners who receive substantial benefit from energy developments are more likely to welcome such development.

**b) Consistent with developing market for sequestration property rights and policies in other states.** A private market for pore space for $CO_2$ sequestration is already developing in several states, as developers successfully offer money to landowners to acquire favorable injection sites. This developing market relies on the traditional conception of property rights (*i.e.*, that property cannot be used without acquiring the right to do so from the property owner). Some states — Wyoming, Montana, and North Dakota — have already passed legislation that provides for compensating landowners for carbon sequestration, consistent with the traditional approach. In light of these precedents, California property owners might be hostile to an alternative approach under which they may not receive compensation.

**c) Ability to deal with holdouts through unitization.** The risk of holdouts is present whenever large parcels of land with fragmented ownership must be assembled for a development project. For public projects, this problem is often addressed by the government's power of eminent domain. Secondary oil recovery, which typically involves injecting water to produce otherwise unrecoverable oil and gas, implicates this same risk of holdouts, because it requires coordinating activities across properties owned by different parties. Many states have addressed this problem by creating a statutory process through which multiple properties can be brought together and operated as a single unit for secondary oil recovery.[65] Through such statutory unitization processes, all property owners in an area can caused to participate in a producing unit, and receive their share of production. In some instances, operators are shielded from claims by neighboring property owners who may be affected by the unit operations but who are not participating.[66]

Wyoming, Montana, and North Dakota have addressed the risk of holdouts by applying the unitization concept to carbon sequestration. For example, under SB 498 in Montana, once a carbon sequestration project controls subsurface storage rights to 60% of the storage capacity in a proposed storage area, it can apply to unitize the storage area. All participating property owners will share in proceeds of the project whether they joined the unit voluntarily or under the statute.

Unitization also has advantages over condemnation. The fair market value of condemned property is determined by what is taken rather than what is created.[67] Thus, property owners may not share in the upside of the $CO_2$ sequestration project. In contrast, holders of unitized oil and gas leases continue to share in the upside. Similarly, carbon sequestration proceeds could be allocated to the owners of the storage rights within a unitized storage area, such that they have a stake in the financial upside of the project but are not liable for damages. This could make them more amenable to such a process, especially in light of the fact that their individual subsurface storage rights may be worth little in a condemnation proceeding.

**Negatives:**



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[65] Statutory or compulsory unitization is distinct from contractual or voluntary unitization, which relies upon unitization clauses that are often found within oil and gas leases. California's limited compulsory unitization statute is found at CAL. PUB. RES. CODE §§ 3630 *et seq.* Contractual unitization requires that the various leases contain compatible unitization clauses. Furthermore, contractual unitization only works if all of the lessees are willing to unitize; if not, contractual unitization is ineffective.

[66] *See, e.g.*, *Baumgartner v. Gulf Oil Corp.*, 168 N.W.2d 510, 516 (Neb 1969) (holding that "where a secondary recovery project has been authorized by the [Nebraska Oil and Gas Conservation C]ommission the operator is not liable for willful trespass to owners who refused to join the project when the injected recovery substance moves across lease lines," because public policy seeks to avoid the waste of natural resources that would occur absent secondary recovery). As such, unitization could be useful for addressing issues related to brine displacement in saline formations as well.

[67] *See Pacific Gas & Elec. Co. v. Zuckerman*, 234 Cal. Rptr. 630, 637 (Cal. Ct. App. 1987).

**d) Transaction costs.** Obtaining property rights from private property owners, whether it be through negotiated agreements, unitization, or condemnation, will undoubtedly result in transaction costs, especially for commercial scale sequestration projects, which may require 100 to 200 square miles of pore space rights.[68] To the extent that geologic structures suitable for carbon sequestration are owned by multiple parties, which is almost certainly the case given the large size of these structures, transaction costs will increase. This inefficiency that could impede the implementation of carbon sequestration, especially in situations where ownership is highly fragmented, if unitization is not an option. However, because developers are currently acquiring sequestration rights in some states, notwithstanding fragmented ownership, the inefficiencies may not be significant.

**e) Potential for holdouts.** Building upon the transaction costs associated with negotiated agreements, unless there is a way to address the risk of holdouts, the actual development of carbon sequestration project could be delayed or be more capital intensive. Unitization and eminent domain could both serve as mechanisms to deal with this risk, but both create additional problems. For example, the time saved by not having to buy out holdouts through a negotiated agreement could be consumed by litigation related to the unitization or condemnation. Further, unless these mechanisms allow carbon sequestration projects to use pore space pending an allocation/compensation decision (*e.g.*, a quick take provision), the timeline for actual implementation could still be quite long.[69] Note that eminent domain authority may be granted by the CPUC in connection with natural gas storage development, which is similar to $CO_2$ sequestration, if on a smaller scale.

**f) Increased operating costs.** The need to compensate property owners for the use of pore space will increase the operational cost structure for carbon sequestration projects. This could mean that some percentage of potential carbon sequestration projects will not be economically viable. But the same could be said of wind or solar projects (*i.e.*, if access to land were free more projects would be viable). Payments to landowners in wind and solar development are not the deciding factor in project economics.

**g) Potential continued uncertainty regarding ownership of pore space.** Ownership of pore space is not typically set out in the deeds that split property into surface and mineral estates. Consequently, there is often uncertainty as to who has the right to use the pore spaces absent the presence of oil or gas. Those states that have addressed the pore space property right issue have created interpretive presumptions regarding prior conveyances of property. For example, there is a rebuttable presumption under Wyoming's HB 89 that pore space is owned by the surface owner. This presumption, however, is not conclusive, which means that courts may still need to determine who owns the pore space for a particular property. Obtaining such determinations could delay the implementation of carbon sequestration projects.

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[68] An optimal site for carbon sequestration would have a geologic structure that limits lateral expansion of the $CO_2$ plume and has multiple injection zones, which would decrease the size of the area for which pore space property rights are needed.

[69] Under CAL. CODE CIV. PRO. § 1255.410, a "quick take" in California requires at least 60 days, and if opposed the condemnor must demonstrate that "there is an overriding need" to possess the property now, "a substantial hardship" will occur if the quick take is denied, and that substantial hardship outweighs any hardship on the condemnee.

*IV.3.b. Limited Private Property Approach – CCSREG Concept*

Instead of an absolute right to pore space, some commentators have suggested that landowners' rights to deep formations are not absolute. These commentators suggest that unless a landowner can show that it has a reasonable and foreseeable use of deep pore space (e.g. for oil and gas development or natural gas storage) then the state can make use of the pore space without compensation to the landowner.[70] Consequently, so long as the sequestration of $CO_2$ would not interfere with other reasonable and foreseeable uses, a carbon sequestration project would not need to obtain the right to use pore space from property owners.

This approach is most prominently reflected in the CCS Reg Project's recently published model legislation. Under this model legislation, a carbon sequestration project could apply for a "pore space permit," which would convey the exclusive privilege to access and use identified pore space for carbon sequestration. Prior to issuing a pore space permit, the state environmental protection agency would conduct a proceeding in which holders of a "non-speculative economic interest" (*i.e.*, the ability to lease the pore space for oil and gas development or natural gas storage) could participate. Anyone that did not participate in this proceeding would waive any and all subsurface property rights that might be affected by the proposed carbon sequestration project. If the injection and sequestration of $CO_2$ would cause actual and substantial damages to such an interest, then either (i) the project would be modified to avoid the damages, (ii) the carbon sequestration project would have to negotiate an agreement with the holder of the interest, or (iii) the state environmental protection agency could authorize condemnation of the interest.

In summary, under this approach, unless a landowner could show current or imminent mineral or other subsurface activities with substantial economic value, the landowner would have no subsurface property rights and a carbon sequestration project could proceed simply by obtaining a pore space permit.[71] If such subsurface property rights were demonstrated to exist, then the carbon sequestration project would address these rights through means similar to those described under the traditional private property approach (*e.g.*, negotiated agreements or condemnation).

**Legislation Needed:** The limited private property approach would require legislation that:

- establishes the process by which pore space property rights are adjudicated,
- defines a "fair" threshold at which a property right to pore space is recognized (*e.g.*, "non-speculative economic interest" in the CCS Reg Project's model legislation), and
- allows for eminent domain of recognized pore space rights, including pore space containing minerals and pore space owned by state and local governments.

**Positives:**

[70] See *Chance v. BP Chemicals, Inc.*, 670 N.E.2d 985, 993 (Ohio 1996) (holding that migrating hazardous waste did not constitute a trespass because landowner's ownership of deep pore space was not absolute).

[71] The Kentucky legislature considered a bill with a similar approach this year. HB 491 would have declared geologic strata beneath 5,500 feet that does not contain either "recoverable or marketable" minerals or water that can be used for a beneficial purpose to be property of the state.

**a) Pore space permit not required.** Under the CCS Reg Project's model legislation, there is no requirement that a pore space permit be obtained. Consequently, developers who have already acquired carbon sequestration property rights by traditional methods would not be required to utilize this process.

**b) Property rights adjudicated once and for all in a unified process.** By addressing property rights in an adjudicative proceeding prior to injection, carbon sequestration projects would have greater certainty regarding risk of legal liability. Further, by utilizing a unified process, carbon sequestration projects would avoid piecemeal litigation.

**c) Application to saline formations.** Most property owners probably would not have current or imminent subsurface activities of substantial economic value in geological structures containing only saline formations (to the extent that evidence exists that the formations do not contain oil or gas). Because this approach eliminates private pore space property rights for this category of property owners, this approach could be advantageous for encouraging carbon sequestration in saline formations.

**Negatives:**

**d) Inconsistent with public perception of property rights.** There is a long history of oil and gas exploration, and more recently the creation of gas storage projects, wind farms and solar energy projects in the Central Valley of California, all created under the traditional property law approach. Landowners may believe they are losing something of value if their property is appropriated for $CO_2$ sequestration without compensation. For this reason, landowners may be hostile to sequestration projects.

One of the sticks in property owners' bundle of rights is the right to explore for valuable minerals. However, under this approach, owners whose property had not been explored, and thus did not have a non-speculative economic interest, might be told they had "waived" their pore space rights. This could be perceived as unfair, especially (1) as landowners often have neither the financial wherewithal nor the technical expertise themselves to explore for valuable minerals, (2) if nearby properties had been explored and valuable minerals had been found, and (3) in light of technological advances that make previously unrecoverable minerals recoverable (*e.g.*, horizontal drilling and fracturing now allow recovery from oil shales and gas shales).

**e) Inconsistent with developing market for sequestration property rights.** It is unclear whether carbon sequestration leases and easements previously obtained through negotiation would be considered a non-speculative economic interest in the adjudicatory process. If not, existing sequestration easements and leases obtained by early movers could be worthless, which could delay actual implementation of sequestration projects and anger those property owners that thought they would be receiving remuneration for granting carbon sequestration rights.

**f) Expertise of adjudicatory entity.** Subsurface property rights can be very complex, especially with respect to the chain of title. The adjudicatory entity would require not only the expertise to resolve these issues, but also a sufficient reputation to support the legitimacy of its decisions in the public's eye. It may well be difficult for a state environmental protection agency, as under the CCS Reg Project's model legislation, to build such expertise for subsurface property right adjudications.

**g) Application to mineral rights.** Even if surface owners do not have realistic expectation for using geological structures suitable for carbon sequestration, mineral estate owners undeniably have an expectation that they may explore the subsurface. The limited private property approach, however, only recognizes that right if there is the ability to economically recover actual mineral resources in the very near future. This creates a number of problems. First, the scope of what economically recoverable mineral resources changes with the price of the resource. More oil is economically recoverable when the price is at $80/barrel than at $40/barrel. Consequently, a mineral owner's "property rights" under this approach would depend upon market conditions at a particular point in time. Second, knowledge regarding the existence of mineral resources is limited. A mineral estate owner may know that valuable minerals exist beneath a property but does not yet know whether they are economically recoverable. Similarly, an area's geology may suggest that valuable minerals exist underneath the surface, but until the subsurface is explored, no one knows whether that is really true. Third, as described above, what is recoverable can change in the future due to technological advances. Consequently, mineral owners' rights may be eliminated under this approach because the property has not yet been explored or the minerals are not economically recoverable under current market conditions or with current technology.[72] Mineral owners would almost certainly oppose this approach for these reasons.

**h) Oil and Gas Reservoirs.** This approach does not apply neatly to carbon sequestration that might occur in depleted oil and gas reservoirs. The mineral estate owners in that situation may still have non-speculative economic interests (*e.g.*, secondary recovery could be used to produce additional oil or the reservoir may be leased for natural gas storage). Consequently, the carbon sequestration project would have to utilize the traditional private property approach's tools (*e.g.*, negotiated agreements and unitization or condemnation). This approach then may not do anything to substantially advance implementation of projects in these reservoirs. In California, oil and gas leases are pervasive in the same areas where there are saline formations suitable for carbon sequestration. Most oil and gas leases provide the lessee with the exclusive right to explore all subsurface formations. That means even carbon sequestration projects proposed for saline formations will likely have to work with mineral lessees who have already purchased the right to explore all formations in the property.

### *IV.3.c. Public Resource Approach*

Aquifer storage and recovery ("ASR") law could serve as a model for a third approach, a "public resource approach, at least for carbon sequestration in saline formations. In *Alameda County Water District v. Niles Sand & Gravel Co.* a gravel operator alleged that the flooding of his gravel pits that resulted from an ASR program constituted a taking because it interfered with subsurface rights and the business operations.[73] Recognizing that the regulation of the state's water resources was a constitutional exercise of the state's police power, the California Court of Appeals held that the water district's activities were a legitimate exercise of the police power and that the adverse effect on the gravel operator's use of its property was not compensable.[74] This line of reasoning is somewhat analogous to the rationale of preventing the waste of natural

[72] It is also unclear what would happen if valuable minerals were discovered in the course of the sequestration project. Would these be the property of the state? The carbon sequestration project? The prior mineral estate owner?

[73] 112 Cal. Rptr. 846 (Cal. Ct. App. 1974).

[74] *Id.* at 855. *See also Board of County Commissioners v. Park County Sportsmen's Ranch, LLP*, 45 P.3d 693, 707 (Colo. 2002) ("[B]y reason of Colorado's constitution, statutes, and case precedent, neither surface water, nor ground water, nor the use rights thereto, *nor the water-bearing capacity of natural formations belong to a landowner* as a stick in the property rights bundle.") (emphasis added)).

resources that underlies trespass cases involving secondary recovery in oil and gas fields.[75] To the extent that California under its police power can use saline formations and the geologic structures in which they occur for public purposes, legislation potentially could be enacted that authorizes the use of saline formations for carbon sequestration without infringing upon private subsurface property rights. It may be necessary to establish that a formation is indeed saline only and devoid of economic amounts of oil and gas, which could make this approach similar to the limited private property approach.

**Legislation Needed:** The Public Resource Approach would require legislation that:

- recognizes saline formations as public resources for the purposes of sequestration projects; and

- authorizes a public agency to either conduct sequestration operations or to permit private entities to conduct sequestration operations on the public's behalf.

**Positives:**

**a) Does not require acquisition of pore space rights.** Acquiring pore space rights, whether it be under the traditional private property approach or the limited private property approach will take both time and money. In contrast, the public resource approach may eliminate the need to spend time and money acquiring pore space rights.

**Negatives:**

**b) Uncertainty regarding utilizing police power to effect carbon sequestration in saline formations.** Western states, including California, have long recognized the value of fresh water and the need to protect it. This recognition underlies freshwater aquifer storage jurisprudence. Similarly, there is plenty of legal support for statutory unitization and governmental authorization of secondary recovery operations in order to prevent the waste of oil and gas. In contrast, carbon sequestration is a new concept. Consequently, there would be legal uncertainty regarding the state's use of saline formations for carbon sequestration. Resolving this issue in court could delay implementation of carbon sequestration projects.

**c) Application limited to saline formations.** Although saline formations may have the largest carbon sequestration capacity, some see depleted oil and gas reservoirs as the low-hanging fruit. However, this approach is not easily applicable to such reservoirs, because injecting $CO_2$ may result in the recovery of previously unrecoverable oil and gas, or may interfere with ongoing oil and gas recovery projects. By being limited to saline formations, this approach may not help spur early carbon sequestration projects. Further, establishing that any given formation, believed to be a saline formation, is devoid of oil and gas or other resources could be a challenge. If landowners assert that there may be oil and gas in a formation, as evidenced by the willingness of third parties to lease their land for exploration, adjudication of that issue may result in the public resource approach becoming similar to the limited private property approach.

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[75] *See, e.g., Railroad Com. of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962) (holding that migrating water from secondary recovery operations authorized by Railroad Commission order in non-unitized field did not constitute a trespass on adjacent mineral estate because this would discourage secondary recovery). *See also* footnote 66 above.

**d) Could require creation of public sequestration entity.** Reliance on the state's police power may necessitate that a public entity do the sequestration, just as a water district was conducting the ASR operation in *Alameda County Water District*.[76] One must consider how quickly a public entity could actually implement a carbon sequestration project in an era of uncertain public finances. Further, the potential for liability will accompany any public entity that is actually conducting injection and sequestration operations.

e) **Eliminates private sequestration rights in saline formations.** This approach, like the limited private property approach, could be perceived as taking the pore space rights of many property owners and could encounter public opposition for this reason. Further, this approach could wipe out investments that private parties may have made in obtaining sequestration rights in saline formations, which could delay implementation of carbon sequestration projects.

## ***IV.4. Requirements for Measurement, Monitoring and Verification (MMV)*** [

*IV.4.a. No well-defined State Law or Regulation*

*IV.4.b. But Lots of Relevant Models from Elsewhere and CARB has mechanisms to independently review and, where relevant, adopt a third-party effort into State regulation*

*IV.4.c. Impact of MRV requirement under EPA's forthcoming GHG Reporting Rule*

*IV.4.d. Options for California [pros and cons]*

## ***IV.5. Long-Term Stewardship of Storage Sites***

*IV.5.a. Federal/State Interactions*

*IV.5.B. Options for California [pros and cons]*

## ***IV.6. Role of Public Outreach, Education and Acceptance***

Despite growing awareness of CCS in the energy, agriculture/forestry, environmental science, and policy communities, the general public remains largely uninformed about CCS technology and its potential role in mitigating adverse climate change. Given the magnitude of the challenge posed by global climate change, it's in California's interest to have a knowledgeable populace prepared to engage in setting and implementing the state's climate and energy policies.

The first step to meaningful public engagement on CCS is public understanding. It is natural for people unfamiliar with a technology to approach it with skepticism and concern, and it is the obligation of CCS policy and project stakeholders to invest in public outreach and education.

It's advisable to begin public discussions of CCS by reminding people of the fundamental nature of $CO_2$. It's a non-toxic, non-flammable, natural constituent of the atmosphere that plays an

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[76] However, courts have upheld private entities' use of unappropriated pore space in the oil and gas context when that use is authorized by a public entity. *See, e.g., Railroad Com. of Texas v. Manziel*, 361 S.W.2d 560 (Tex. 1962).

essential role in plant photosynthesis and in regulating the climate. It's not *carbon monoxide*. Too much $CO_2$ in the air, however, is leading to global warming and other climatic changes. And too much $CO_2$ in a confined, unventilated space can pose a serious health and safety concern. At the depth that $CO_2$ would be stored geologically, the water table pressure makes it compress to a liquid-like "dense phase."

The concept of long-term storage of captured industrial $CO_2$ in deep geologic formations also may be misunderstood. People don't normally have a familiarity with depth into the earth in the way they do for height into the sky. Water wells are typically tens to hundreds of feet deep, whereas $CO_2$ storage takes place at least 3,000 feet deep (more than a half-mile) and often at 5,000-10,000 feet deep. The latter is the height of eight Empire State Buildings stacked on top of one another. Commentators have observed that with CCS, the expression NIMBY (Not In My Back Yard) can switch to NUMBY (Not Under My Back Yard), but people's gut reaction may not take into account how far under the surface that $CO_2$ would actually be stored. Nonetheless, $CO_2$ storage sites are explicitly chosen where layers of sealing rock or other trapping mechanisms promise to keep injected $CO_2$ from migrating to the surface.

Aside from understanding that the subsurface has layers, like the Grand Canyon, people are generally unaware of microscopic features or current uses of the deep porous rock formations. Many don't realize, for example, that rocks hold fluids in tiny pores, not caverns or fissures. Most people don't know that oil production routinely involves pumping a lot of water to the surface with the oil, separating it, and reinjecting it. Or that wastewater injection is a common disposal practice. Many haven't been told that waters in porous rock formations are usually saltier at greater depth and that $CO_2$ storage projects target such "saline formations" that are well sealed from shallower freshwater aquifers.

Nonetheless, risks associated with CCS projects are real, and need to be evaluated carefully by project developers and regulators. Their communication and discussion is facilitated by primers for the public on CCS fundamentals.

One aspect of CCS that is now much more in the public lexicon is drilling terminology, particularly "blowout preventers" and their intended function and possible malfunction in the wake of the Deepwater Horizon well failure. The incident may also heighten concerns about the potential for large and rapid $CO_2$ releases from CCS projects. It will be important for CCS project developers and regulators to explain the similarities and differences between the buoyancy forces and subsurface behaviors for hydrocarbons and dense-phase $CO_2$.

#### *IV.6.a. Public Outreach by California Agencies with CCS Jurisdiction*

The activities of three California agencies engaged in CCS public outreach and education—the California Energy Commission, the California Air Resources Board, and the California Public Utilities Commission—are described below. Each has found it beneficial to position CCS within the context of policy initiatives and other mitigation technologies for combating global climate change. When CCS is presented in this manner, the public can better weigh its potential to contribute to the state's goal of protecting human health and the environment while meeting energy demand and fostering economic growth and opportunity.

##### *IV.6.a.(i). California Energy Commission/WESTCARB Public Outreach Activities*

In the area of CCS, the Energy Commission's research and outreach efforts are chiefly conducted through the West Coast Regional Carbon Sequestration Partnership (WESTCARB), which is funded by the U.S. Department of Energy (DOE) and the Energy Commission (which also manages the partnership). WESTCARB's website (http://www.westcarb.org) conveys current information on CCS technology, project activities, and links to news stories, climate change reports, presentations, and study results. The Energy Commission has also independently funded researchers at the University of California–Berkeley to examine the factors contributing to public perceptions toward CCS.

WESTCARB's outreach program—coordinated by the Energy Commission's Media Office—has included the following activities:

- Project fact sheets
- Carbon sequestration technology primers
- Annual technical meetings with Q&A/discussion sessions (open to the public)
- Public educational workshops, jointly sponsored with universities and nonprofit organizations, tailored to stakeholder issues of regional significance (e.g., forest management in the Pacific Northwest, oil production in Kern County, California)
- Public meetings for communities near proposed project sites, usually in conjunction with a project's local partners
- Presentation of WESTCARB results at major CCS technical conferences and forums
- Topical workshops on CCS as part of the biennial Integrated Energy Policy Report (IEPR) series prepared by the Energy Commission
- News releases and media interviews
- Public/cable television documentaries
- Middle and high school teacher trainings, in conjunction with the Keystone Center's "CSI: Climate Status Investigations" series
- Field testing of Climate Action Reserve's protocols for forestry-based carbon sequestration projects
- Contribution to DOE's *Carbon Sequestration Atlas of the United States and Canada*
- Contribution to DOE's *Best Practices Manual for Public Outreach and Education for Carbon Storage Projects*

Particularly noteworthy was WESTCARB's role in developing the report, *Geologic Carbon Sequestration Strategies for California: Report to the Legislature*, in response to Assembly Bill 1925, which was passed unanimously by the Legislature in 2006 (the same session that produced Assembly Bill 32, the Global Warming Solutions Act of 2006).

*IV.6.a.(ii). Air Resources Board Public Outreach Activities*

The California Environmental Protection Agency's Air Resources Board (ARB) holds the primary responsibility for monitoring and regulating sources of greenhouse gases in order to reduce emissions. In preparing the AB 32 Climate Change Scoping Plan, ARB undertook a broad and extensive public outreach and engagement effort involving dozens of workshops, meetings, and webcasts throughout the state. Hundreds of Californians attended these events and provided suggestions for improving the Plan. Additionally, ARB received thousands of letters, postcards, e-mails, and other comments. All told, more than 42,000 people voiced an opinion on the Plan.

Public outreach remains an important element in the implementation of AB 32, which calls for a steering committee of state agencies, the state's air districts, and public and private entities to "develop a coordinated array of messages and draw upon a wide range of messengers to deliver them." Further directive notes, "These will include regional and local governments whose individual outreach campaigns can reinforce the broader State outreach themes while also delivering more targeted messages directly tied to specific local and regional programs." An AB

32 Environmental Justice Advisory Committee and other advisory bodies can assist with messaging and delivery to assure inclusiveness.
As the role of CCS grows in the future, ARB will step up its public processes for CCS education and outreach. Examples from other air quality programs include placards, fact sheets, webcasts and workshops, FAQs, news releases and an RSS news feed, and a topical e-mail service for subscribers.

*IV.6.a.(iii). Public Utilities Commission Public Outreach Activities*
The California Public Utilities Commission (CPUC) has a deep experience base in consumer education and outreach as part of its activities regulating investor-owned electric and natural gas utilities operating in California This includes a Public Advisor's Office and a separate Business and Community Outreach program to assist California communities, local governments, and businesses. The Public Advisor's Office regularly resolves complaints and administers public participation hearings on controversial open proceedings before the CPUC. The Business and Community Outreach program sponsors five Outreach Officers to represent the agency throughout California and to assist communities in understanding CPUC programs and policies. These outreach officers schedule workshops and presentations in communities to explain current policy efforts, actively solicit consumers' feedback, and resolve issues before complaints escalate.

CPUC has been addressing CCS education and outreach in conjunction with stakeholder group meetings and support for feasibility studies on the Hydrogen Energy California gasification combined-cycle power project with $CO_2$ capture for enhanced oil recovery. A public panel discussion on "Carbon Capture and Storage and the Role It Plays in Climate Change Mitigation," held in early 2010, is available for viewing as a video archive. Support for CCS research and development is noted in the RD&D section of the Energy Action Plan, which CPUC developed jointly with the Energy Commission.

*IV.6.b. Permitting Agency Outreach Activities*
Although the permitting process for CCS projects in California is not yet completely clear, it is clear that the responsible permitting agencies will need to provide a concise delineation of the permitting process—what steps are followed to obtain a permit, what areas the permit covers, and how the permit is administered—so that the public can understand the agency's response to the proposer's application. Permitting agencies can further facilitate public understanding by distributing materials explaining the fundamentals for CCS and by allowing for extra time at public meetings for basic questions and answers.

Public agencies with jurisdiction over CCS projects will interact with stakeholders on many levels, however, outreach to communities surrounding proposed project sites will be particularly important and should be as inclusive as possible. Good community relations is an essential element to sustainable public policy, and although each community is unique, major groups to consider in outreach planning include elected and safety officials; neighboring landowners and tenants; business, civic, environmental, and religious groups; neighborhood associations; schoolteachers; and local media.

*IV.6.c. Public Outreach Opportunities for California Educators*
For California's educators, CCS represents an opportunity to develop or expand curricula to provide students with the education and training to find gainful employment in this newly emerging field. A broad range of professionals work on CCS, including geologists, hydrologists, engineers, drill rig crews, and chemists. A robust CCS industry will create new well-paying jobs, and teachers and professors may need to receive additional training to be able to teach and

mentor their students. Already, many California schools and universities partner with industry practitioners to conduct field research. The involvement of teachers and students, particularly in early CCS projects, should be encouraged.

In addition to serving students with professional pursuits, California educators can help create a populace well informed on CCS fundamentals (as well as other climate change mitigation measures), contributing toward sound energy and climate policymaking.

### ***IV.7. Commercial Considerations/Incentives/Policy Drivers***

#### *IV.7.a. Significant policy/fiscal incentives do not exist in California*

#### *IV.7.b. Incentives for Initial Early Movers*

#### *IV.7.b.(i) MOU structure*

#### *IV.7.c. Incentives for Established Projects*

#### *IV.7.c.(i) New legislation*

#### *IV.7.d. Options for California [pros and cons]*

### ***IV.8. Environmental Justice – Peridas***

The Environmental Justice (EJ) movement was born to addresses the statistical fact that people who live, work and play in America's most polluted environments are commonly people of color and the poor.[77] Communities of color, which are often poor themselves, are routinely targeted to host facilities that have negative environmental impacts, or have historically co-habited the same areas as those facilities. The EJ movement has been championed primarily by African-Americans, Latinos, Asians, Pacific Islanders and Native Americans. The pollution can take the form of air, water or land pollution, but the domination of resources such as land or water by those facilities is also at issue with environmental justice, as is economic welfare and a community's sense of justice itself. The health effects resulting from exposure to pollution are widely recognized, while specific studies at EJ communities have shown how these communities exhibit higher levels of illness, disease and premature deaths than in other areas.[78]

The EPA defines environmental justice as "the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies".[79] The Agency explains that "'fair treatment' means that no group of people should bear a disproportionate share of the negative environmental consequences resulting from industrial, governmental and commercial operations or policies".[80] Further, EPA explains that "'meaningful involvement' means that people have an opportunity to participate in decisions about activities that may affect their environment and/or health; the public's contribution can influence the regulatory agency's decision; their concerns will be considered in the decision making process; and the decision makers seek out and facilitate the involvement of those potentially affected".[81]

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[77] Ref.
[78] Ref.
[79] See: http://www.epa.gov/compliance/ej/
[80] See: http://www.epa.gov/compliance/ej/basics/index.html
[81] Id.

California state law defines environmental justice to mean "fair treatment of people of all races, cultures, and incomes with respect to the development of environmental laws, regulations, and policies".[82] EJ advocates, according to a presentation to this Panel[83], would be more expansive and define environmental justice as everything in the EPA definition plus the avoidance of disproportionate environmental impacts on communities of low income residents and people of color, including:
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- Cumulative health impacts on a region or community
- Fair and equitable use of government spending
- Health considerations sharing equal consideration with economic interests
- Long term sustainability issues
- Fixing the health problems of dirty air and finding co-benefits of reductions in GHG emissions

Typical concerns of EJ communities revolve around large industrial facilities such as power plants, refineries, cement plants, chemical plants, as well as truck and ship traffic and issues associated with dumping and incineration sites. Fossil fuels are often at the center of EJ concerns for a number of reasons that include the air, land and water impacts associated with their extraction or production (e.g. coal mining or oil/gas wells), the emissions from their refining and combustion, and their waste byproducts (e.g. coal ash and petroleum coke). EJ activists commonly advocate a move away from the extraction and use of fossil fuels, and their replacement with clean, sustainable alternatives.[84]

In relation to CCS, a number of factors could lead to EJ concerns, depending on the location of a project. This is largely due to the fact that such projects will typically be complex set-ups that feature an industrial facility where the CO2 is captured, a pipeline to transport it, and a sequestration site.

The capture plant is likely to be of most concern to EJ communities, due to its size and complexity. Such a plant may, or may not, present additional issues over and above a similar plant without CO2 capture. In the case of a power plant, for example, it is possible that CO2 capture may involve the use of some additional chemicals which are not commonly used in power plants, but which are used in industrial facilities elsewhere. It is also possible that the land footprint of a plant with capture will be larger, although this is likely to be an incremental difference rather than one of orders of magnitude.

Pipelines transporting CO2 do not differ in any significant respect to pipelines transporting other substances. In some cases, CO2 is a more benign substance that poses lower risks than, for example, flammable natural gas.[85] The siting of these pipelines, therefore, is not expected to pose any EJ issues over and above typical pipeline proposals.

The sequestration of CO2 will require some infrastructure to be built. Typically, this will comprise injection and monitoring wells, and some minimal access to land for geophysical monitoring. The number of wells for a new facility injecting in a saline formation will range from approximately 2-20, with the most likely number being in the middle-to-low end of the range,

[82] Ref.
[83] Ref. Tom Frantz presentation
[84] Ref: Jane Williams presentation from August meeting.
[85] Point to relevant section elsewhere in the report, or add external ref.

depending on the site's geologic characteristics. For an operational EOR site, existing wells could be used entirely, or some new wells added, along with CO2 separation facilities.

It is therefore evident that the siting of CCS projects does have EJ dimensions, as would be expected for large industrial facilities. The siting of a new plant capture plant is likely to be of most concern, and will carry the essentially same considerations for air, land and water as a plant without capture. In addition, some particular aspects of a CCS plant, such as the use of specific chemicals, greater truck traffic or a slightly larger surface footprint might raise some additional incremental issues that go beyond the base plant without CCS. The pipeline transportation and sequestration of CO2 should present a smaller challenge as far as EJ is concerned, because the surface footprint is smaller, the infrastructure of a far smaller scale, and the emissions sources far fewer compared to the capture plant. This does not eliminate concerns however, as previous siting of oil and gas wells in highly populated and EJ areas is a reality and problematic from both an environmental and equity standpoint. It is possible that even a handful of CO2 injection and monitoring wells be the straw that breaks the camel's back if location is chose poorly.

More generally, previous experience with industrial activities and facilities is likely to color EJ communities' reaction to CCS proposals as well as their perception of the risks of CCS itself. As a result, despite the scientific consensus that the risks related to the sequestration side of a well-sited and operated project are similar to commonly performed activities such as natural gas storage and enhanced oil recovery[86], it is expected that some segments of the population in EJ communities will regard the injection of CO2 itself as a dangerous, dumping activity, akin to the dumping of waste, and treat it as an EJ issue per se. Others might take a different view of the risks involved.

Based on the above, we do not see CCS as a technology that poses additional EJ concerns over and above what current industrial activities pose, but we recognize that these concerns are numerous. California should be mindful of EJ concerns and issues when it comes to siting CCS projects, and ensure that their impacts are mitigated and that they do not unfairly affect disproportionately burdened communities. At the same time, the State should seek to meet its energy needs through clean and sustainable means to the extent possible. We discuss this further in the Recommendations chapter.



[86] IPCC SRCCS ref.

# V. Review Panel Recommendations

## *V.1. The Regulatory Framework for Permitting CCS Projects*

Permitting of CCS projects, in theory, covers four discrete activities: (1) installation and operation of capture equipment at the source; (2) pipeline transportation; (3) geologic injection; and (4) separate permitting of the geologic storage site. As discussed below, the Panel believes that only the fourth of these – separate permitting of geologic storage sites – constitutes a significant "permitting impediment" at this time.

In making this judgment, we are cognizant of the fact that California does not have, nor should endeavor, to establish a overly detailed CCS regulatory framework for commercial CCS projects now that endeavors to forecast and resolve in advance each issue that may arise in a CCS project. As a practical matter, only a handful of commercial-scale CCS projects would be expected to advance in California (or any State, for that matter) in the years ahead. This is because CCS technology still needs to be commercially demonstrated in many applications (perhaps most notably of which is electric power generation); moreover, due to the cost and complexity, commercial-scale projects are apt to be deployed initially on only a handful of large GHG emitters in any given State. Thus, the Panel does not believe that it is necessary or prudent for California to endeavor to set up a CCS regulatory regime that would apply to all potential commercial projects down the road. California instead needs to focus on what is needed by the handful of initial demonstration, and thereafter commercial, projects that already have emerged and will continue to emerge in the years ahead.

We also are cognizant of the desire by industry to have "unitary" permitting for CCS projects – i.e., the ability to deal with one State regulator for all aspects of CCS project. While we perceive the obvious benefits of such an approach to both regulators and the regulated community alike, we believe that it is impractical for California to endeavor to accomplish that outcome at this time for three reasons.

First, CCS projects are almost piecemeal by definition, with different private sector entities typically responsible for source, pipeline, and sink activities. Pipeline operators, for example, generally do not construct, own and operate capture equipment. Similarly, it is not envisioned that power companies would initially get in the business of owning and operating geologic storage sites. Thus, the concept of a "CCS project" may be somewhat of a misnomer. While all of these disparate pieces must come together and be addressed thoroughly and thoughtfully from a regulatory perspective, it may be naïve to envision that a unitary CCS permitting agency will, or should, ever emerge.

Second, and similarly, each component of a CCS project requires different regulatory expertise, from geology on the one hand to air permitters on the other hand. Short of a grand reorganization of multiple California agencies, meshing the necessary expertise into one agency seems infeasible, unwise – and, as we explain below – unnecessary.

Third, as stated above, we do not believe that it is necessary for California, at this time, to resolve every conceivable regulatory issue that may emerge in a future CCS project. The more prudent path is to focus on those regulatory changes that are needed to get the first projects up and running – and such an incremental approach cautions against major regulatory reorganizations.

*V.1.a. Regulatory Framework for Installation and Operation of the Capture Equipment at the Source.*
Except as noted below, the Panel recommends that California take no separate action with respect to the installation and operation of the capture equipment at the source because State agencies, such as the Air Resources Board and local air quality management districts, either (i) already have existing authority to address these requirements, (ii) are in the midst of modifying their authorities in compliance with EPA's SIP Call (the SIP Call only applies to the Sacramento Metropolitan AQMD), or (iii) will be subject to the FIP that will impose those requirements directly from EPA. Stated another way, we see no need for California to attempt to depart from the PSD GHG permitting program that EPA is setting up for the States pursuant to the Tailoring Rule by, for example, imposing even more stringent requirements, which presumably would be allowed by the CAA.

For similar reasons, and with respect to a GHG accounting methodology for CCS, we recommend that ARB consider the forthcoming Pew methodology in the first instance. That methodology should be ready by early 2011. We recognize that ARB will need to vet and revise that methodology through its own administrative procedures, all of which should be done. We believe, however, that it would be most efficient and effective for California to take advantage of work that others, such as Pew, have already done or are doing in this area, instead of endeavoring to reinvent the wheel.
The Panel believes, however, that it is critical for ARB to recognize CCS earlier and more explicitly as a mitigation technology under AB32. Similarly, using existing authorities, ARB and the California Energy Commission should be directed to develop a compliance pathway for carbon-based transportation fuels that are producing using CCS under the Low Carbon Fuel Standard (LCFS). The applicable LCFS regulatory materials already acknowledge that a CCS pathway should be developed.

*V.1.b. Regulatory Framework for Pipelines.*
We discuss pipelines below.

*V.1.c. Regulatory Framework for Injection.*
California's obligations here will be governed by EPA's forthcoming final Class VI UIC rule. If that rule allows primacy for Class VI, we recommend that DOGGR seek such primacy. For reasons of regulatory efficiency and expertise, we believe that DOGGR is the logical State agency to run the Class VI program. If DOGGR balks at this suggestion (for reasons of funding or staffing, for example), we recommend that California not seek primacy for Class VI (if the final rule allows that) and that, instead, California allow EPA Region 9 to run the program for the State.

In order to ensure that the authority of the State Water Boards is preserved with respect to issuing and enforcing permits for any discharge that may affect surface or groundwater policy, we suggest that DOGGR coordinate with the State Water Boards as necessary and appropriate in the implementation of Class VI wells permitting. We understand that the State Water Boards and the Department of Conservation have a 1988 Memorandum of Understanding (MOU) related to Class II wells. If necessary, we recommend that that MOU be amended to cover Class VI, too.

*V.1.d. Regulatory Framework for Permitting of Geologic Storage Sites.*
The Panel believes that the absence of a regulatory framework for the separate permitting of geologic storage sites in California constitutes the major "permitting impediment" to projects.

*V.1.d.(i). Projects are Private Lands*

All of the other States that have looked at this issue have adopted new laws that establish comprehensive and rigorous permitting, operating, and site-closure obligations on the owner and/or operator of the geologic storage site. These laws (and regulations to be issued pursuant to them) cover topics such as site suitability, public participation, whether pore space has been obtained, site closure obligations and the like. These requirements sit aside and thus will compliment, not duplicate, EPA's forthcoming Class VI UIC rule. That rule focuses on well-standards and operations, with its regulatory endpoint of concern being the protection of USDWs. A comprehensive geologic site permitting program, on the other hand, would require the applicant to obtain its relevant UIC permit and meet other requirements to protect public health and the environment beyond USDWs.

We thus recommend that California enact a similar law; suggested legislative language is below. We suggest that DOGGR be responsible for all geologic storage sites under that new authority. DOGGR, in turn, would enter into MOUs with relevant agencies to facilitate permitting and, to the extent possible, approach an "unitary" permitting model.

One MOU should be created between DOGGR and the California Energy Commission (CEC), which has statutory responsibility for licensing thermal power plants equal to or greater than 50 MW and such plants' related facilities, such as transmission lines, fuel supply lines, and water pipelines. CEC also acts as the lead State agency and its process is a certified regulatory program under the California Environmental Quality Act (CEQA). This CEQA process, including the evidentiary record and associated analyses, is functionally equivalent to the preparation of an environmental impact report. As such, CEC has a responsibility to determine if proposed thermal power plants 50 MW (and larger) have a significant environmental impact resulting from their GHG emissions, and if so, to mitigate such impacts if possible. We thus further recommend that CEC be tasked with drafting GHG guidelines under CEQA. Similarly, the California Public Utilities Commission (CPUC), which is the lead State agency for CEQA purposes for thermal power plants less than 50 MW, should be tasked with drafting comparable GHG CEQA guidelines for those facilities.

Another MOU (or a series of MOUs) should be created between DOGGR and relevant counties and/or AQMDs with respect to permitting geologic storage site for refineries, cement plants, foundries and ethanol plants.

[Note to Panel: CPUC has authority to approve or deny ratepayer funding for CCS activities, including FEED studies and PPAs, so this perhaps should be discussed in the incentive section.]

*V.1d.(ii). Projects on State Lands*

The Panel recommends that California prepare a separate report on conducting geologic storage operations on State lands. [Or will we make recommendations here, too?]

*V.1.d.(iii). Projects under State Waters*

[To be provided?]

*V.1.d.(iv). Projects on Federal Lands in California*

As noted above, the federal government is working on permitting programs for projects on federal lands (including pipeline access and the like). The Panel encourages California to coordinate with the federal government on this important endeavor. We note, for example, that California has a history of entering into MOUs with federal agencies for energy project development on federal lands.

### *V.2. Regulation and Permitting of $CO_2$ Pipelines*

The Panel understands that California law and regulation is already reasonably well developed with respect to pipelines, including some existing authorities that could be interpreted to include carbon dioxide pipelines. Interstate $CO_2$ pipelines are a matter of federal authority, so our recommends pertain onto to intrastate pipelines.

With respect to safety regulation, CPUC has oversight authority over intrastate natural gas pipelines. CPUC sets and monitors standards of gas quality and pressures as well as pipeline materials. CPUC General Order 112-E adopts federal standards from 49 C.F.R. parts 191, 192 and 199 and further adds some reporting requirements in addition to the federal standards. We note, however, that DOT's $CO_2$ pipeline regulations appear in part 195 of title 49 of the Code of Federal Regulations, so apparently would not be picked up and enforced by CPUC General Order 112-E.

With respect to rate/economic regulation, the CPUC has economic regulatory authority over pipelines that offer "transportation" services to the public and qualify as a "common carrier utility." If any intrastate CO2 pipelines qualify as a utility, they would be regulated by this existing authority.

With respect to eminent domain for siting intrastate CO2 pipelines, we recommend that existing authorities be amended to allow such pipelines to invoke eminent domain in the same manner as natural gas pipelines.

### *V.3. Ownership of Pore Space for $CO_2$ Storage*

The Panel understands that California law regarding pore space ownership either does not exist or is unsettled, particularly with respect to storage rights in non EOR reservoirs.

The emerging "American Rule" of pore space ownership is that the pore space: (i) belongs to the surface owner, (ii) may be severed; and (iii) is subject to the same property laws that apply in a given State, such as California, to pore space that is used for natural gas storage. This is the approach: (i) already adopted by several other States, such as Wyoming (see Wyoming HB 89 (2008)); (ii) recommended by the Interstate Oil & Gas Compact Commission in its model CCS rules; and (iii) adopted by S. 1856, the pending federal bill that would clarify pore space ownership under federal lands.[87] The American Rule recognizes and preserves the dominance of the mineral estate.

The Panel recommends that California follow the American Rule through enactment of prospective legislation that amends the applicable provisions of the State's real property code.

Except as otherwise provided in this report (for pipelines, for example), the Panel further recommends that California not undertake to address unitization or condemnation of property rights for CCS projects, including pore space, at this time, because: (1) the Panel does not perceive the lack of unitization or condemnation authorities as an initial impediment to California's initial CCS projects; and (ii) the granting of unitization or condemnation rights may

[87] The Panel is cognizant of the important differences between natural gas storage and the geological sequestration of carbon dioxide. P. Marston, "From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage," 29 Energy Law. Journal 421, 475 (2008).

trigger understandable public concerns about property rights. California may choose to revisit these topics at a future date, as necessary and appropriate.

Suggested legislative text is below.

### ***V.4. Requirements for Measurement, Monitoring and Verification***

### ***V.5. Long-Term Stewardship of Storage Sites***

### ***V.6. Role of Public Outreach, Education and Input***

In developing policies for CCS, California's agencies will want to use transparent processes and provide multiple opportunities for public input. Companion efforts to further public education on CCS will be essential to meaningful public engagement.

- Recommendations:
- Allocate sufficient time and resources to support an inclusive outreach effort
- Engage and provide a public forum for knowledgeable independent experts on CCS subjects
- Communicate the scope, methods, and findings of risk assessments in an honest and open manner
- Communicate in the language and through the channels most familiar to target audiences
- Provide ample and non-intimidating vehicles for public comment
- Keep outreach materials up-to-date and aligned with policy developments
- Look for opportunities to share and coordinate outreach materials among agencies

### ***V.7. Commercial Considerations/Incentives/Policy Drivers***

### ***V.8. Environmental Justice***

As outlined in section IV.5, this Panel recognizes clearly that the deployment of CCS technology, much like the siting of any other major industrial infrastructure, can have EJ implications depending on the location, and on the exact nature of the technology used in each case. The Panel also finds that CCS poses no additional concerns of a purely environmental nature that are not encountered in existing industrial applications. In relation to the geologic sequestration of CO2, we reiterate the overwhelming consensus that properly sited and operated projects do not pose any risks over and above those found in routine industrial applications such as natural gas storage and enhanced oil recovery.[88] Concerns about large scale releases of CO2 and mass

[88] IPCC quote.

fatalities or injuries, although understandable from an EJ perspective, are not justified from a scientific point of view, and these scenarios are impossible in practice.

This Panel does not represent the range of EJ communities and advocates. As such, we do not feel qualified to offer a set of recommendations on what is a complex issue that cuts across several areas of law, policy and administration. A number of documents have been compiled by EJ advisory committees to that effect, and we urge the reader to study those.[89] rom the Panel's standpoint, we express the desire to find ways to deploy CCS as a climate mitigation technology without impacting EJ communities, and our conviction that this can be done, both from an environmental standpoint and from an economic equity standpoint. Proper siting, project design and regulatory oversight can mitigate the environmental impacts of CCS projects. At the same time, although we see CCS occupying the upper portion of the climate mitigation cost curve, we believe that it can avoid pushing other technologies even further up their own cost curve, thereby reducing overall compliance cost. Properly designed policies should shield the poor sections of the population from cost increases, not just from CCS, but of all climate mitigation

### ***V.9. Draft Resolution/Legislative Language***

[to be provided once we know what we are going to say!]

[89] See, for example: "Recommendations of the California Environmental Protection Agency (Cal/EPA) Advisory Committee on Environmental Justice to the Cal/EPA Interagency Working Group on Environmental Justice", Approved by the Committee on September 30, 2003, Published Date: October 7, 2003;

## VI. Appendices

*II.2.b. Testimony*

1. List in Appendix

*II.2.c. Written Comments*

2. List in Appendix

*II.2.d. Technical Advisory Committee Support*

3. List of papers in Appendix